ONTARIO POWER GENERATION

ANNUAL INFORMATION FORM

FOR THE YEAR ENDED DECEMBER 31, 2002

ONTARIO POWER GENERATION INC.

March 31 , 2003

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All references to dollars in this annual information form are in Canadian dollars. In this annual information form, "Province" refers to the Government of the Province of Ontario (provincial government entity) and "Ontario" refers to the Province of Ontario (geographic area). This annual information form uses certain technical and other terms relating to the electricity industry. See "Glossary" for the definitions or explanations of these terms.

ITEM 1 - CORPORATE STRUCTURE

Ontario Power Generation Inc. (the "Corporation") was originally incorporated under the OBCA on December 1, 1998. On April 1, 1999, as part of the reorganization of Ontario Hydro and the related restructuring of the electricity industry in Ontario, the Corporation and its subsidiaries (collectively "OPG") purchased and assumed certain employees, assets, rights and obligations of the electricity generation business of Ontario Hydro (the "Acquired Business"). On January 1, 2003, 16 of its wholly-owned subsidiaries were amalgamated with the Corporation under the *Business Corporations Act* (Ontario) (the "OBCA"). The primary purpose of the amalgamation was to simplify the existing corporate structure.

OPG's principal business is the generation and sale of electricity. OPG is one of the largest generators of electricity in North America. OPG sells the electricity that it generates into the markets administered by the Independent Electricity Market Operator (the "IMO"). In turn the electricity is acquired by wholesale customers for use or sale within Ontario or into interconnected markets.

As of December 31, 2002, OPG's in-service electricity generation portfolio, with a total net in-service capacity of 22,211 MW consisted of: two nuclear plants (four units at Darlington and four units at Pickering B), six fossil fuelled generating stations; 36 hydroelectric generating stations; and a green energy portfolio of 29 small hydro and two wind generating stations. In addition, OPG's Pickering A nuclear generating station, with a net in-service capacity of 2,060 MW, was laid up in late 1997 and is in the process of being returned to service on a unit by unit basis. The Bruce A and B nuclear generating stations are owned by OPG, however, these stations are leased on a long-term basis to Bruce Power L.P. ("Bruce Power") and are excluded from OPG's generation statistics.

OPG's stations offer dispatch flexibility of base load, intermediate and peak capacity and are diversified by fuel type and technology.

OPG's organizational structure is summarized as follows:

Generation Subsidiaries: OPG's hydroelectric and fossil generation assets were held through subsidiaries of the Corporation through 2002, which were amalgamated with the Corporation on January 1, 2003. OPG's nuclear generation assets are held through subsidiaries of the Corporation; the Pickering and Darlington assets are leased back to and operated by the Corporation.

Other Investments: OPG also holds a 48.79% interest in Integran Technologies Inc., an engineering services company, a 50% interest in Brighton Beach Power Ltd., a 49.95% interest in Brighton Beach Power L.P., a 50% interest in Huron Wind Inc., a 49.99% interest in Huron Wind L.P., a 50% interest in Portlands Energy Centre Inc. and 49.95% interest in Portlands Energy Centre L.P.

Unless noted otherwise, each of the foregoing corporations is wholly-owned by the Corporation and incorporated under the OBCA. Each of the foregoing limited partnerships were formed under the *Limited Partnerships Act* (Ontario).

The information contained in this annual information form concerning OPG or the Corporation for periods prior to April 1, 1999 relates to the electricity generation business that was previously owned and operated by Ontario Hydro and is now owned and operated by OPG, unless the context indicates otherwise. In May 2001, OPG completed the agreement for the long term lease of its Bruce A and Bruce B generating stations. The information contained in this annual information form applicable to periods since commencement of the lease does not include

these stations, unless specifically noted to the contrary. In addition, unless specifically noted to the contrary, the information contained in this annual information form does not include the four hydroelectric stations on the Mississagi River system which the Corporation sold to Mississagi Power Trust in May 2002.

ITEM 2 - BACKGROUND

Overview

The electricity industry is principally made up of four components: generation, transmission, distribution and marketing of energy and other services in wholesale and retail markets. Generation is the production of electricity at generating stations. Transmission is the transfer of electricity across high-voltage power lines from generating stations to local areas or large users. Distribution is the delivery of electricity within local areas to homes and businesses using relatively low-voltage power lines.

Electricity has traditionally been generated by large multi-unit centralized stations. These stations are generally classified by (i) the type of fuel used at the station, (ii) capacity, typically expressed in megawatts ("MW"); and (iii) dispatch mode (i.e. whether the electricity generated by a particular generating station is dispatched to meet peak, intermediate or base load demand). The energy produced by a station is generally expressed in terms of megawatt-hours ("MWh").

Generating stations are called upon to produce electricity and are "dispatched" based on demand. "Base load capacity" stations operate virtually continuously to satisfy relatively constant demand. "Peaking capacity" stations operate intermittently to provide electricity during periods of maximum demand. "Intermediate capacity" stations operate fewer hours than base load capacity stations but more than peaking capacity stations. Typically, base load facilities are higher capital cost, lower operating cost facilities, while intermediate and peaking facilities are characterized by lower capital costs but higher operating costs and greater flexibility. These facilities have generally been dispatched based on a system whereby the lowest available marginal cost generating unit is dispatched to meet the "next" unit of electricity required to meet the demand in the area served by the electrical system.

Electricity is an essential commodity that cannot be easily or economically stored in large volumes. Generation of electricity must instantaneously match demand if the stability and reliability of the system is to be maintained. Consequently, it is important to coordinate the supply of and demand for electricity. This responsibility is typically assigned to independent system operators. Electricity systems have evolved on a regional basis and are generally interconnected with their neighbouring regional power grids. Such interconnections not only enhance system reliability, but also permit the economic purchase and sale of electricity in interconnected electricity markets.

Traditionally, electric utilities have been vertically integrated monopolies that built generating, transmission and distribution facilities to serve the needs of the customers in their service territories. Significant capital commitments were required to construct large power stations and to coordinate generation, transmission and distribution. Historically, the price of electricity was set by a regulatory process, rather than by market forces, whereby rates were established to recover the cost of producing and delivering power to consumers, as well as recovery of capital costs. Under this monopoly service regime, customers had no choice of supplier and suppliers were not free to pursue customers outside their designated service territories.

In some jurisdictions, programs were established as early as the 1970s to encourage the development of generation capacity by independent, or non-utility, generators. These generators typically entered into long-term contracts with host utilities to sell power at prices reflecting the utility's avoided cost related to the supply of electricity.

Restructuring in the Electricity Industry

A number of jurisdictions, including the United Kingdom, continental Europe, Australia, New Zealand, parts of South America and parts the United States and Canada, have embarked on a process of restructuring their electricity industries by moving away from vertically integrated monopolies and towards more competitive market models.

There are a number of elements common to these restructurings, including the following five common assumptions: (i) the generation of electricity and the provision of energy services to end-users are not natural monopolies. Accordingly, the general approach has been that generation should be open to competition and end-users should be given the opportunity to choose their source of supply; (ii) the price of energy and the addition of new capacity should be driven by market forces; (iii) transmission and distribution are natural monopolies and are best managed through an independent regulator and access to transmission and distribution networks should be open on a non-discriminatory basis to generators, retailers and consumers of electricity; (iv) an independent system operator should be created to maintain system reliability and security and to ensure non-discriminatory access to these common carrier transmission systems; (v) an independent market operator should facilitate market-driven commercial power transactions. The roles of an independent system operator and an independent market operator could be performed separately or by a single operator.

Commercial power transactions in deregulated markets are often executed through a central power exchange (or "pool") administered by an independent market operator. Specifically, offers of energy at specified prices are made or "offered" into the power pool and sufficient generation capacity is dispatched to meet demand. Purchasers can "bid" to buy power at these "spot market" prices or, alternatively, purchasers can enter into contracts with retailers to determine the price at which electricity will be supplied.

The distinct differences between the competitive (generation and retailing) and regulated (transmission and distribution) segments of the industry have been recognized by market participants, not only from a regulatory standpoint but also from the perspective of the differing risks and the skills and conditions required for the efficient operation of each segment. In certain jurisdictions, the market design requires functional, financial and corporate separation of these segments. This has resulted in an increase in the number of separate specialized generation, transmission and distribution companies, many of which have been created through spin-offs from previously vertically integrated utilities. Also, a number of companies which originated as independent, or non-utility, generators in the 1970s and 1980s have grown to be significant generation-focused companies. In addition, there has been a trend towards the convergence of the electricity and natural gas sectors, particularly as a significant majority of the new generation under construction in North America is expected to be fuelled by natural gas. This has resulted in an increasing number of major companies in the natural gas industry becoming significant participants in aspects of the electricity industry. Similarly, major companies in the electricity industry are becoming significant participants in aspects of the natural gas industry.

Although the elements described above have generally been followed, various jurisdictions are implementing industry restructuring in a variety of ways. The restructurings vary regarding the design of each market's rules for competition to supply energy and the rules governing the degree of access given to extra-jurisdictional suppliers. In areas where inter-regional access was previously limited, mechanisms to facilitate the development of larger markets are being established, subject to availability of physical interconnection capacity.

The implementation of electricity industry restructurings and the operation of competitive energy markets can be significantly impacted by the characteristics of each market area, including demand/supply balances, the extent of transmission capacity to facilitate energy imports necessary to meet market demand and the diversity of generation by fuel type and the related exposure to and management of fluctuations in market prices of fuel types such as natural gas. These factors all contribute to energy price volatility. In designing and planning the market structure and rules for competition in their jurisdictions, governments, regulators and other industry participants are influenced by local market characteristics and experience in other jurisdictions.

More recently, for a variety of reasons, the move to restructure the electricity industry in North America has slowed. In many jurisdictions the changes to encourage competitive markets has led to significant building of new generation capacity, resulting in a relatively rapid, and in some cases significant, change from degrees of undersupply of generation capacity to oversupply. Periods of high and volatile electricity prices, and related expectations for significant growth in demand and development, have been replaced by markedly lower prices, reduction in the frequency and extent of price volatility and diminished growth prospects. This in turn has resulted in dramatically reduced financial and capital market performance particularly for participants in the once burgeoning electricity trading sector but also more generally for parties engaging in competitive generation activities. Many participants in this sector have significantly reduced new building activity and are attempting to sell assets to reduce levels of indebtedness. These and other factors have resulted in North America seeing various hybrid restructuring arrangements. There are various efforts underway to pursue the appropriate model, including an effort by FERC in

the U.S. to develop a Standard Market Design ("SMD"), but there are competing interests and considerations and the process is likely to take some time with a period of uncertainty and difference in approach.

Restructuring in Ontario's Electricity Industry

Until April 1999, Ontario Hydro was a vertically integrated electricity utility and the sole supplier of electricity for most of Ontario's consumers. In November 1997, the Province released a policy paper entitled "Direction for Change" which set out a restructuring plan for the electricity industry in Ontario intended to cause the electricity industry to operate without government financing. The goals of restructuring included creating a competitive market for electricity and facilitating the maintenance of a financially viable electricity industry in Ontario.

In January 1998, the Minister of Energy, Science and Technology established the Market Design Committee to make recommendations to the Province on the commercialization and design of an independent market operator to manage the wholesale electricity market. The independent market operator was to oversee the operation of the integrated power system and to create the rules and protocols necessary to implement a competitive electricity market in Ontario. The Market Design Committee produced three quarterly reports in 1998 and a final report in January 1999. During this period, the market restructuring legislation, the *Energy Competition Act, 1998*, was enacted.

As a result of this process, five principal successors to Ontario Hydro's integrated electricity businesses began operating as separate entities on April 1, 1999:

- Ontario Power Generation Inc., which purchased and assumed the electricity generation, wholesale energy and ancillary services businesses;
- Hydro One Inc. ("Hydro One"), which purchased and assumed the transmission, rural distribution and retail energy services businesses;
- the Independent Electricity Market Operator (the "IMO"), which was formed to act as both the independent electricity system operator and market operator, responsible for the dispatch of generation to meet demand, the control of the Ontario transmission grid and the operation of energy and ancillary markets;
- the Electrical Safety Authority, which was established to carry out electrical equipment and electrical wiring installation inspection functions; and
- the Ontario Electricity Financial Corporation (the "OEFC"), which remains responsible for managing and retiring Ontario Hydro's outstanding debt and other obligations and for the administration of non-utility generator contracts in a manner compatible with the new market design.

Ontario's Electricity Market

As a result of the opening of Ontario's electricity market to competition on May 1, 2002 ("Market Opening"), there have been significant changes in the way the electricity market operates in Ontario. Generators, both from within and outside Ontario, compete to sell electricity through the IMO-administered spot market. Other market participants include local distribution companies, large industrial facilities directly connected to the transmission system, other large industrial and commercial customers connected to the distribution system who opt to be wholesale market participants and retailers. Most larger end-users have the option of either purchasing electricity at the spot-market price or contracting with a licensed energy retailer. At the retail level, most smaller end-users currently pay a regulated fixed price for the electricity they consume. See *"Background – Ontario's Electricity Market – Recent Changes to the Ontario Electricity Market"*.

All market participants must be authorized by the IMO to cause or permit electricity to be conveyed into, through or out of the IMO-controlled grid and to participate in the IMO-administered markets. All market participants that supply electricity into, or take electricity from, the IMO-controlled grid must install approved interval metering at their connection points to the grid. The IMO dispatches generators based on their offers to sell electricity and operating reserve. See *"Business of OPG – Regulation – Ontario's Electricity Industry – The IMO"*.

In addition, the IMO and all generators, transmitters, distributors, wholesale sellers, wholesale buyers and retailers must obtain a licence from the Ontario Energy Board ("OEB") in order to participate in the Ontario electricity market. OPG has received licences from the OEB as a generator, a wholesale buyer and seller and a retailer.

Consumers pay for the energy purchased as well as for transmission, distribution and charges payable to the IMO in relation to its activities and other costs incurred (referred to as "administrative charges" and "uplift charges", respectively). In addition, a debt retirement charge of $7.00 per MWh is levied to service the portion of OEFC's debt that cannot be serviced by payments made by OPG, Hydro One and the local distribution companies. See *"Business of OPG – Relationship with the Province and Others – Stranded Debt, Proxy Taxes and Effect of Change in Ownership on Tax Status"*.

The following provides an overview of the roles of the principal market participants involved in the generation, sale and distribution of electricity in Ontario's new electricity market:

Generators

Generators function as suppliers of energy and operating reserve that is priced by the IMO-administered market. Prices in the IMO-administered market will fluctuate but generators may fix the price that they receive for the sale of electricity by entering into bilateral contracts with third parties. See *"Background – Ontario's Electricity Market – Other Financial Instruments"*. Generators may also sell ancillary products to the IMO-controlled grid, including reactive support/voltage control service, certified black start facilities and automatic generation control.

The IMO

The IMO functions both as independent system operator, ensuring overall system reliability and stability by controlling physical dispatch and directing the operation of the transmission system, and as an independent market operator of the spot market which in effect operates as a power exchange. As the market operator, it functions as the clearing house for the settlement of spot transactions by suppliers and purchasers of electricity in the IMO spot market. See *"Business of OPG – Regulation – Ontario's Electricity Industry – The IMO"*.

Market Intermediaries

Market intermediaries include wholesale buyers and sellers, distributors and retailers. Wholesale sellers may provide financial or risk management products to facilitate such things as price-volatility protection and may purchase energy on a spot basis out of the pool for subsequent resale into interconnected markets at either prevailing spot prices in those markets or to other non-Ontario end-users. Distribution companies distribute electricity from the IMO-controlled grid or other distributors to end-use customers in their regions. Distributors acquire their electricity from the spot market or from wholesale sellers under terms approved by the OEB to meet their obligations to provide regulated supply to consumers who do not choose an alternative energy supplier. Retailers may purchase energy from the spot market or from wholesale sellers and resell that energy to end-users, although given that most retail customers now pay a fixed price of 4.3 cents/kWh for the electricity that they consume, they do not have an incentive to buy from a retailer. See *"Background – Ontario's Electricity Market – Recent Changes to the Ontario Electricity Market"*.

Ontario End-Users

Ontario end-users include industrial, commercial and residential consumers. Large end-users, if they are directly connected to the IMO-controlled grid, have the option of purchasing energy directly from the IMO-administered market or from a retailer. Other end-users are generally expected to purchase from a retailer or their distributor.

Interconnected Markets

The interconnected markets are those energy markets in neighbouring provinces and states whose transmission systems are connected to the Ontario power grid either directly or through other contiguous interconnected markets. Ontario's markets are interconnected with the northeastern quadrant of North America, including the U.S. northeast and midwest, Manitoba and Québec. Market intermediaries wishing to sell electricity

into the interconnected markets are required to purchase the electricity out of the IMO-administered spot market for resale into the interconnected markets.

Market Power Mitigation

OPG holds a large proportion of the generation capacity in Ontario. In order to address the issue of the potential exercise of market power, OPG is subject to the "market power mitigation" measures established in its generation licence. These measures, the key elements of which are a rebate mechanism and a commitment to relinquish effective control over a major portion of its generating capacity, have a significant influence on OPG's corporate strategy and business prospects. For more detailed information about these measures, see *"Business of OPG – Regulation – Ontario's Electricity Industry – Market Power Mitigation"*.

Recent Changes to the Ontario Electricity Market

On December 9, 2002, the Province modified the legislation governing the Ontario electricity market by enacting the *Electricity Pricing, Conservation and Supply Act, 2002*. This legislation and related regulations include the following key features:

- effective December 1, 2002 (but retroactive to Market Opening) and at least until April 30, 2006, the price of electricity paid by 'low-volume consumers' (consumers using less than 150,000 kWh annually, although this cap was subsequently increased to 250,000 kWh, as described below) and other 'designated consumers' is fixed at 4.3 cents/kWh;

- 'designated consumers' include municipalities, universities, colleges, school boards, hospitals, nursing homes, charities, condominiums, apartments, consumers who have a demand of 50 kW or less and others as may be specified by regulation;

- a mechanism for refunding low-volume and designated consumers the difference between 4.3 cents/kWh and the amount they actually paid for electricity between Market Opening and December 1, 2002;

- wholesale market uplift charges to distributors, low-volume consumers and designated consumers are capped at 0.62 cents/kWh;

- charges for transmission and distribution and fees for the operation of the IMO are capped at current levels (see below);

- the Minister of Energy has been given the power to review Market Rule amendments to ensure that they do not unduly and adversely affect the interests of consumers with respect to price or the reliability or quality of electricity service. The Minister has also been given powers to: (i) approve the IMO's proposed expenditure and revenue requirements and fees before they are submitted to the OEB; (ii) approve the filing with the OEB of applications by transmitters and distributors for rate increases; (iii) amend the rates approved by the OEB; and (iv) to require that certain orders of the OEB be amended; and

- tax incentives are created to promote conservation, use of alternate fuels and support for clean energy production through a variety of mechanisms.

On March 21, 2003, the Province announced a business protection plan for large electricity consumers in Ontario. Under this plan, consumers using up to 250,000 kWh per year will be included in the fixed price rate of 4.3 cents/kWh, retroactive to May 1, 2002. Except for certain designated consumers, all consumers using above 250,000 kWh per year will remain in the competitive wholesale and retail markets and receive rebates under the terms of the existing MPMA arrangements for the 12 months ending April 30, 2003. Effective May 1, 2003, rebates to these customers will be fixed at 50 % of the amount by which the average spot price in the IMO-administered market exceeds 3.8 cents/kWh, with rebates paid on a quarterly basis. OPG will continue to be responsible for a rebate commitment based on the existing MPMA arrangement under which the level of payment is impacted by the degree of decontrol implemented by OPG, however, payable on a quarterly basis going forward. See *"Regulation –*

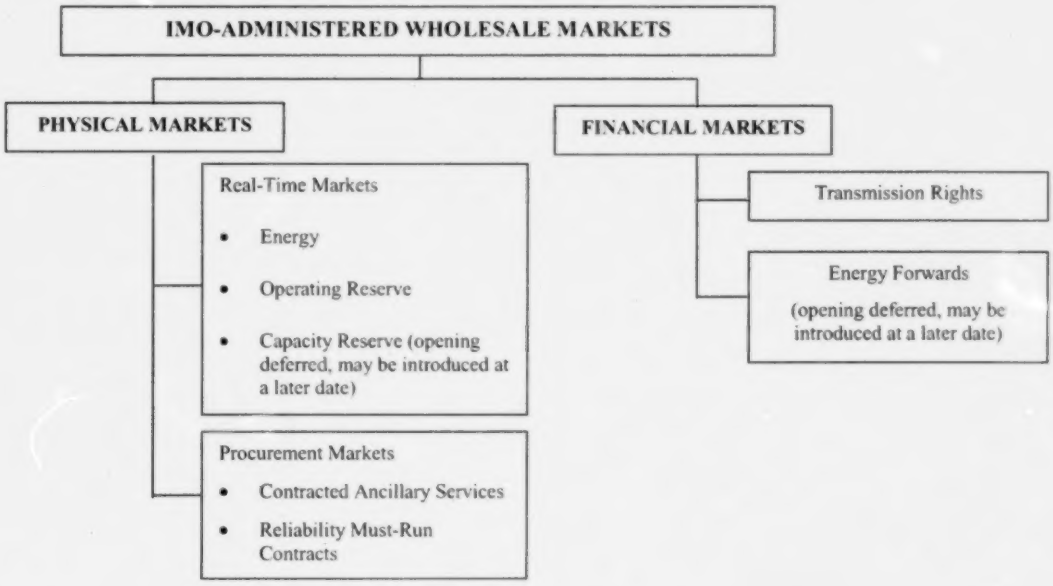
Market Power Mitigation – Rebate Mechanism and Transitional Price". This business protection plan is not expected to have a material impact on OPG's operating results.

The Province has also announced related matters, including: (i) changes to OPG's Board of Directors, which currently has two vacancies; (ii) an independent investigation into delays in and the cost of restarting OPG's Pickering A nuclear generating station; (iii) acceleration of OPG's assessment of a new 550 MW generation project on OPG's Portlands site in Toronto; (iv) possible construction of an additional tunnel at OPG's Beck hydroelectric generating station at Niagara; and (v) a Ministry of Energy feasibility study of constructing another hydroelectric generating station at OPG's Beck hydroelectric generating station.

The new legislation and related regulations do not materially change the wholesale market for electricity, including the determination of energy prices in, or operation of, the IMO-administered market. However, the number of participants in the wholesale market is expected to decrease as certain consumers no longer need to hedge the price of the electricity they expect to consume, as the Province has fixed the price for them. As a result of these changes, approximately 50% of the electricity consumed in Ontario is subject to this fixed price.

The IMO-Administered Wholesale Markets

The IMO-administered wholesale market for energy services consists of both physical markets, relating to the dispatch and pricing of electricity and ancillary services and financial markets, which are focused on financial risk management associated with the exposure to spot market energy prices and to transmission constraints. The following chart provides an illustration of the products and services that are available in the IMO-administered market, as well as some additional products and services which may be introduced at a later date.



The IMO Physical Markets

The IMO-administered physical electricity markets consist of both real-time and procurement markets: real-time markets for energy and operating reserve and, if implemented, capacity reserve and procurement markets for additional generation-related services to maintain reliability of the transmission grid. For more information about these markets, see *"Business of OPG - Regulation – Ontario's Electricity Industry – The IMO"*.

Spot market prices in the IMO-administered real time market fluctuate significantly as a result of a number of influences, including domestic market demand, operating reserve requirements, generation availability and the volume of imports from and exports to interconnected markets. The highest spot market prices are set during periods of peak demand and are typically set by plants with the highest marginal cost at that point in time. This is usually natural gas generators or facilities with limited energy generation available. During off-peak periods, spot market prices are generally set by plants with a lower marginal cost of production, such as coal-fired generation. Spikes in spot prices are very often weather and capacity driven. Due to the fact that the Ontario market is interconnected with other energy marketplaces, prices in Ontario are also influenced by conditions in those markets.

The IMO is conducting a consultation process on market evolution to address several key market design issues, including the following: (i) implementation of a day ahead market similar to proposals under FERC's standard market design ("SMD"); (ii) optimization of dispatch over multiple intervals rather than the current process which determines dispatch every five minutes; (iii) consideration of some form of locational marginal pricing ("LMP") after the first 18 months following Market Opening (LMP is part of FERC's SMD and is used by both New York and PJM); and iv) a number of proposals to deal with resource adequacy that address generator availability, demand response, capacity markets and resource adequacy obligations on the IMO or distributors/retailers. In addition, the Market Surveillance Panel has recently issued a discussion paper in which they argue for the elimination of certain payments made by generators and importers of electricity. These payments compensate generators and importers for lost sales when constraints on the transmission system prevent the delivery of electricity that would otherwise be sold into the IMO-administered market.

A number of initiatives to deal with the supply of electrical generation were announced in November 2002 and included in Bill 210. See "*Background – Ontario's Electricity Market – Recent Changes to the Ontario Electricity Market*".

The IMO Financial Markets

The IMO-administered financial markets are intended to provide wholesale market participants with risk management opportunities through the trading of transmission rights and energy forward contracts.

Transmission rights are sold to market participants by the IMO in scheduled auctions. The operation of the transmission rights market is intended to provide market participants with a financial hedge for congestion when importing or exporting energy. Congestion occurs at a time when the IMO receives more bids or offers than can be accommodated given the available limits on transmission capacity between Ontario and the interconnected market at an inter-tie. When the flows of electricity are such that an inter-tie reaches its capacity, it results in variations in energy prices on either side of the inter-tie. Transmission rights are a financial risk management instrument and do not provide a market participant with priority access to transmit electricity across an inter-tie. Transmission rights may be purchased or sold notwithstanding that the purchaser or vendor is not offering to purchase or sell electricity across an inter-tie. They do, however, entitle a purchaser to a payment from the IMO in the event of congestion at the inter-tie.

The opening of an IMO energy forward market has been deferred. An IMO energy forward market would be designed to operate one day ahead of the actual physical market day, allowing participants to hedge offers or bids for specified quantities of energy for each hour of the next day based on the clearing price in the forward market.

Other Financial Instruments

Market participants may choose to sell financial risk management products to intermediaries or consumers within or outside of Ontario that are designed to reduce exposure to volatility in spot market prices. These contracts, sometimes referred to as bilateral contracts or contracts for differences, are derivative contracts that do not involve the physical delivery of energy. They are, however, of interest to generators and consumers of energy who sell or purchase electricity at a floating price, as they have the effect of fixing the price at which such parties sell and purchase electricity. For example, generators in the new market sell electricity at the spot market price. To protect against the risk of spot market price decline, a generator may agree with a counterparty that, on a given date in the future, they will exchange a payment equal to the difference between the actual spot market price for the period covered by the contract and a fixed price agreed to by them at the time they enter into the contract. This contract, when entered into between a generator and a consumer of electricity, has the effect of fixing in advance the price at

which they sell and purchase electricity in the future. See "*Business of OPG – Markets and Customers – Commercial Strategy*".

In Ontario, IMO market participants have the option of having the IMO adjust their settlements to reflect these contracts, by registering certain information about such contracts with the IMO, in which event the Market Rules with respect to 'physical bilateral contracts' are applicable. Non-IMO participants will settle directly with retailers or with distributors providing billing services for retailers.

Retail Energy Participants

Distributors are responsible for distributing electricity to all end-users connected to their systems. Currently, most of these consumers are either a 'low volume' or a 'designated consumer' and therefore will pay 4.3 cents/kWh for the electricity they consume. See "*Background – Ontario's Electricity Market – Recent Changes to the Ontario Electricity Market*". To the extent that a consumer is not eligible for the fixed price of 4.3 cents/kWh and has not contracted with a retailer, distributors are obliged to sell electricity to them under the service defined by the OEB as "Standard Supply Service", in most cases at the weighted hourly average price in the Ontario spot market. In order to hedge against the inherent risk in a spot market, consumers can choose to enter into contracts to hedge against the risk of price fluctuations.

Expansion of Inter-Tie Capacity

To encourage the supply of electricity into Ontario from the interconnected markets, Hydro One, as a condition of its OEB licence, is obligated to use its best efforts to expand inter-tie capacity by approximately 2,000 MW within 36 months of Market Opening, subject to governmental and regulatory approvals and environmental assessments. Hydro One has been involved in various inter-tie expansion projects, including: (i) increase the available transfer capability with Michigan, by 500 – 600 MW, in conjunction with International Transmission Company; and (ii) expand existing inter-tie capacity with Québec, by 1,250 MW (however, Hydro-Québec is still in the process of resolving regulatory issues surrounding the project).

ITEM 3 - BUSINESS OF OPG

Overview

OPG is one of the largest electricity generators in North America. OPG's principal business is the generation and sale of electricity. This electricity is sold into the IMO-administered wholesale market. Wholesale buyers purchase electricity from this market for use or sale within Ontario or to interconnected markets in other provinces and the U.S. northeast and midwest. OPG also markets and sells electricity into the interconnected markets of other provinces and the U.S. northeast and midwest. OPG's total generation from its own assets in 2002 was approximately 115.8 TWh. The Ontario market imported 6.9 TWh and exported 3.7 TWh in 2002.

All generators in Ontario, including OPG, must offer their production into the IMO-administered real-time energy market, or spot market, in order to be dispatched by the IMO. OPG is required to offer all available capacity as operating reserve. OPG has also negotiated ancillary services contracts with the IMO. Additionally, OPG capitalizes on opportunities for the provision of financial risk management products to market participants and other customers in Ontario and in interconnected markets.

As of December 31, 2002, OPG's electricity generation portfolio, with a total net in-service capacity of 22,211 MW. OPG's hydroelectric stations had a net in-service capacity of 6,923 MW which is primarily base load capacity, but which also provides intermediate and peak production, subject to water availability. OPG's fossil fleet, which is principally used to provide power for intermediate and peak demand, consists of 9,700 MW of net in-service capacity. These primarily coal-fired generating stations can be called upon relatively quickly to meet variations in demand. OPG's three nuclear generating stations (excluding leased facilities) are located at two sites (one station at Darlington and two stations at Pickering), comprising a total of eight in-service reactor units (four units at Darlington and four units at Pickering B) with 5,588 MW of net in-service capacity and four laid up nuclear units (Pickering A) with 2,060 MW of installed nuclear capacity.

Five Year Generation Summary[1]

	1998		1999		2000		2001		2002	
	Total (TWh)	% of Total	Total (TWh)	% of Total	Total (TWh)	% of Total	Total (TWh)	% of Total	Total (TWh)	% of Total
Hydroelectric	31.9	25	33.6	26	34.0	25	33.7	27.7	34.3	29.6
Fossil	34.2	27	36.1	27	42.4	31	40.2	33.1	39.6	34.2
Nuclear	59.9	48	61.4	47	59.8	44	47.7	39.2	41.9	36.2
Total	126.0	100	131.1	100	136.2	100	121.6	100	115.8	100

Note:
(1) For a more detailed summary see the tables included under "*Business of OPG – Generation Operations*".

OPG holds a large proportion of the generation capacity in Ontario. In order to address the issue of the potential exercise of market power, OPG is subject to the "market power mitigation" measures established in its generating licence. These measures, the key elements of which are a rebate mechanism and a commitment to relinquish effective control over a major portion of its generating capacity, have a significant influence on OPG's corporate strategy and business prospects. For more detailed information about these measures, see "*Business of OPG – Regulation – Ontario's Electricity Industry – Market Power Mitigation*".

Market Opportunities and Challenges

The power industry in Canada and the United States had an end-user market of at least US$245 billion in retail energy sales in 2000 produced by an installed base of approximately 930,000 MW of capacity. In 2000, OPG's regional markets, consisting of Ontario, the U.S. northeast and midwest, Québec and Manitoba, had an end-user market in excess of US$100 billion in retail energy sales.

The move to competitive markets, while slowing and incomplete, has provided an opportunity for efficient, low-cost generators and marketers of power to produce and sell energy at competitive rates and to grow through further investment in new and existing power generation assets. Continued population growth, combined with increasing density in urban areas and demand for heating, air conditioning and electronic infrastructure means the demand for additional electricity generation will continue to grow albeit at modest rates. Balancing supply and demand in certain markets can be particularly difficult given the long lead time to build new power stations and constraints on inter-tie capacity limiting energy imports. Imbalances between supply and demand may result in volatile prices for electricity. However, today most markets in North America have excess capacity and high reserve margins which has dampened pricing and volatility. Nevertheless, generators with available energy, a reliable means of delivery and knowledge of the interconnected electricity system can successfully participate in these markets provided they manage the significant risks referred to below.

In deregulated markets, generators and other market participants must compete with each other largely on the basis of energy price and service. Generators and purchasers of electricity in these markets must manage energy price risk. This provides opportunities to offer products to manage the risk associated with market price fluctuations.

Opportunities for the acquisition of generation assets or their output was initially made possible by electricity deregulation in North America that prompted restructuring including an accompanying divestiture of power plants by companies seeking to reconfigure their businesses. Today, due to the factors described earlier including significant overbuilding and a need to financially restructure to reduce indebtedness, there are a significant number of generating assets available for sale.

While these developments continue to provide new opportunities, they also create new challenges and risks. The ability of OPG to take advantage of the opportunities and face the challenges and risks depends on a variety of factors, including its ability to operate its generating facilities on an increasingly competitive basis, to provide the products and services its customers desire on a profitable basis and to manage the commodity price risks around its generally long electricity position. See "*Business of OPG – Risk Factors*".

Corporate Strategy

OPG's vision is to be a premier North American energy company based in Ontario. To achieve this vision, OPG plans to leverage its strengths and direct its resources to the following strategies: increase production efficiencies and cost-competitiveness of generating operations; capitalize on energy marketing and sales opportunities created in the electricity markets; and create a foundation for participation in an increasingly regional competitive market.

Key Performance Drivers and Initiatives

Improved Efficiencies and Cost Competitiveness

OPG's portfolio of generation assets is well balanced and diversified in terms of technology, fuel type, market and dispatch flexibility. Production costs are low relative to other generators in Ontario and the U.S. northeast and midwest, although higher than generators in Manitoba and Quebec. OPG's fundamental strategy in the near term is to increase the productivity, capacity and cost competitiveness of its generating stations.

OPG continues to focus on the implementation of a $1,145 million multi-year recovery plan that was initiated in 1997 by the former Ontario Hydro to improve the operating performance of its nuclear generating stations over a seven-year period. Under the plan, OPG continues to standardize its operations and implement initiatives to improve: accountability; management and operational control systems; maintenance and inspection programs; regulatory compliance; performance standards; safety; and employee training.

OPG's goal is to achieve top quartile performance for nuclear operations, among North American nuclear generators, based on a nuclear performance index used by the North American members of the Institute of Nuclear Power Operators and the World Association of Nuclear Operators. This index is designed to measure the degree by which a nuclear generator is providing safe and reliable nuclear performance.

OPG's fossil plants operate as base load, intermediate load and peaking stations depending on the particular stations and the time of operation. Plant efficiency, productivity and reduction of airborne emissions are key factors in enhancing competitiveness of these plants. Significant improvements to these stations are in progress, such as the installation of selective catalytic reduction equipment to reduce NO_x emissions on four units, two at Lambton and two at Nanticoke, by the end of 2003, at a cost of approximately $285 million. OPG is also pursuing a broad range of other initiatives, including operational changes, emission reduction credit trading and further implementation of emission control technologies. The successful implementation of these initiatives is intended to maintain the cost competitiveness of OPG's fossil operations relative to other fossil generators in its regional market area and to ensure continued compliance with environmental performance standards in Ontario. The appropriate level of capital expenditures for the fossil facilities can vary significantly and is driven in part by the expected level of operation and availability.

Since 1990, OPG has refurbished and upgraded several of its hydroelectric facilities which has helped increase its hydroelectric capacity. This reinvestment program is continuing, with approximately $300 million expected to be spent over the next five year.

Pickering A Return to Service

The return to service of the four laid-up units at the Pickering A Nuclear Generating Station is a key initiative for OPG. The return to service of all four Pickering A units will add 2,060 MW of reliable, low cost electricity and will make a significant contribution towards improving environmental performance within the Ontario electricity market since nuclear stations produce virtually no emissions resulting in smog, acid rain or global warming. OPG expects to begin commissioning the first unit at various power levels early in the second quarter. OPG has commenced planning for the return to service of the second unit. See *"Business of OPG – Generation Operations – Pickering A Lay-Up and Restart"*.

Energy Marketing and Sales Opportunities

OPG has developed and enhanced its marketing, sales and trading capabilities, with a focus on three key growth areas of the new marketplace: (i) spot market energy sales and trading; (ii) the sale of financial risk management products; and (iii) sales of energy-related products and services to meet customer needs for energy solutions. The successful implementation of this strategy requires an active commercial market predicated on factors such as sophisticated product structuring and risk management skills to correctly price and manage complex structured products, marketplace recognition and brand equity to facilitate customer acquisition and retention and the capability to deliver risk management products that meet customer needs.

Create a Foundation for Competing in Increasingly Regional Markets

Although uncertainty around aspects of energy markets will likely continue to persist in Ontario and North America as a whole in the short term, increasingly the market is becoming more regionalized and interdependent beyond provincial boundaries. Understanding the industry context not only in Ontario but in North America as a whole will play a key role in OPG's competitive position for the future. OPG believes its strategy to be a premier North American energy company is sound yet dependent on factors both within and beyond its control. To preserve a range of options and access to capital OPG will need to be flexible and attuned to market developments to secure its presence in a regional competitive market.

Focus on Core Business Operations

OPG is pursuing initiatives to improve the cost competitiveness and operational flexibility of its business and foster a strong commercial orientation. In doing so, OPG expects to be well positioned to adapt to changing conditions in the Ontario market and to pursue new or expanded business opportunities in the interconnected markets. As part of this initiative, in January 2002, OPG announced a restructuring plan anticipated to lead to a company-wide staff reduction of approximately 2,000 employees over a two to three year period. As at December 31, 2002, OPG has approved severance packages for approximately 1,400 employees. OPG's other initiatives to date include: a renewed commitment to workforce skills development and cooperative labour relations which, combined with company-wide incentive programs, have contributed to greater operational flexibility and enhanced productivity.

OPG has also continued the strategic outsourcing of non-core activities and the reorganization of corporate services, internally or with other parties. This included the outsourcing of its information technology services activities in February 2001 to New Horizon System Solutions Inc., an entity owned by Cap Gemini Canada Inc. and outsourcing certain of its research and development activities with the sale of its interest in Kinectrics Inc. to AEA Technology plc., effective January 2002. In 2002, OPG also finalized the sale of its nuclear safety analysis division to Nuclear Safety Solutions Limited, a subsidiary of NNC Holdings Ltd., a U.K. based international provider of nuclear services.

Other Initiatives

OPG is participating with various partners to add capacity in Ontario that is not controlled by OPG. As noted above OPG is progressing with work required to return to service the four units at Pickering A nuclear generating station. The Brighton Beach joint venture project with ATCO, scheduled to be in-service in 2004, will add an additional 580 MW of capacity. Huron Wind, a joint venture with Bruce Power, the first commercial wind farm in Ontario, is located on the shores of Lake Huron near Kincardine. Huron Wind, which consists of five wind turbines with a total capacity of 9 MW, will market certified green electricity to commercial and industrial customers.

Since its creation in 1999, OPG has focused on advancement of energy technology commercialization that will lead to a sustainable energy future. OPG invests in a number of initiatives which address the Government's alternative energy sourcing objectives including the establishment by OPG of a venture capital subsidiary, OPG Ventures Inc., to invest up to $100 million in new energy generating or related technologies. Various investments have been made to date, such as investments in fibre optic high voltage power measurement, energy generation from waste using plasma gasification and enterprise energy management solutions. OPG's research and development

efforts focus on the advancement of near to market technologies. Current projects include micro-turbine, bio-gas and fuel cell demonstrations, energy storage assessments and aggregation of existing distributed generation technologies for dispatch.

The Province announced in November 2002 that the construction of a third tunnel may proceed at OPG's Sir Adam Beck hydroelectric generating station in Niagara Falls, a project to more fully utilize water available at the station. OPG has been directed by the Province to accelerate its assessment of the feasibility of development of a new generating station, to be located on the site of OPG's decommissioned Hearn generating station in the Portlands' area of Toronto's downtown waterfront. In December 2002, OPG and TransCanada Energy Ltd. announced that they had formed a limited partnership called Portlands Energy Centre L.P. to pursue the development of this site. The partnership will assess the viability of developing a 550 MW combined cycle natural gas-fuelled cogeneration facility to meet the growing energy needs of Toronto's downtown core.

Markets and Customers

OPG's Markets

Ontario Market

In 2001, Ontario's population was approximately 11.9 million and Ontario's real gross domestic product ("GDP") was approximately $426 billion, reflecting an average GDP growth of 4.8% per year for the five-year period from 1997 to 2001. In 2002, Ontario's electricity demand reached 153.2 TWh.

From 1990 to 2002, commercial energy consumption in Ontario (40% of total energy consumption in 2001) increased, reflecting growth in the economy since the early 1990s as evidenced by new construction, declining vacancy rates for existing office and multi-residential buildings and increased use of electronic equipment and air conditioning. Industrial energy consumption (35% of total energy consumption in 2001) decreased from 1990 to 1993 during the period of increasing electricity rates and decreasing economic activity, but increased steadily between 1994 and 2000. In 2001 industrial demand decreased again due to a weak economy and declining energy consumption in Ontario's manufacturing and resource base segments. In 2002, a stronger Ontario economy, a low Canadian dollar and increased Ontario manufactured exports resulted in an increase in industrial electricity demand. Demand in Ontario's residential sector (25% of energy consumption in 2001) declined from 1990 to 1997 due to conversion from electric space and water heating to natural gas and the replacement of some household appliances with more efficient units. Since reaching a low in 1997, however, residential energy consumption has increased in the last five years due to strong growth in housing construction and additional air conditioning installations.

The IMO is responsible for forecasting the demand for electricity in Ontario and for assessing whether the existing and proposed generation and transmission facilities are adequate to meet Ontario's needs. During times of negative reserve margins, the IMO anticipates and relies on the Ontario generators maximizing their availability to offer into the Ontario market, the marketers arranging imports and for customers to reduce their consumption.

On a seasonal basis, demand for electricity in Ontario peaks in both the winter and the summer. Over the past 10 years, the demand for electricity in Ontario peaked in the winter, however, the increase in summer peak demand has outpaced the increase in winter peak demand, resulting in the demand for electricity in Ontario peaking in both the winter and the summer. During 2002, several extremely hot weather spells resulted in new all-time highs in electricity demand in Ontario, with a record peak demand of 25,496 MW set on August 1, 2002.

Interconnected Markets

As a result of the interconnection of the Ontario power grid with transmission systems in neighbouring provinces and states and the interconnections that, in turn, exist between those provinces and states and other jurisdictions, OPG is able to compete with others to buy and sell energy into most electricity markets in the northeast and midwest of North America. OPG has specifically targeted the interconnected markets of the U.S. northeast and midwest as a focus of its energy business. In order to maximize the opportunities in these markets, OPG has obtained the requisite market-based tariff from the U.S. Federal Energy Regulatory Commission ("FERC"). See *"Business of OPG – Regulation – Energy Regulation"*.

FERC is currently encouraging the formation of independent entities to control the transmission system, offer wholesale transmission services and operate energy markets. These entities are referred to as Independent Transmission Providers ("ITPs"), some of which are Regional Transmission Organizations ("RTOs"). An RTO is an independent manager of the transmission systems within its boundaries. RTOs are expected to provide one-stop shopping for transmission access, congestion management and other services, which should improve the ability of market participants to transact on a regional basis. FERC's Standard Market Design proposal also requires RTOs to operate energy markets. OPG's Ontario-based generation is well situated to directly access two operating RTOs. The Midwest Independent System Operator ("MISO") has started offering transmission and other services and is working to become a fully functional RTO, including operating an energy market, over the next one to two years. The MISO service territory covers all or parts of 15 states from North Dakota to Kentucky, as well as Manitoba. Ontario is interconnected with MISO at the Michigan, Minnesota and Manitoba borders. Ontario is also interconnected at the New York border with the New York Independent System Operator ("NYISO"), which in turn is interconnected with ISO-New England, the market operator covering Massachusetts, Connecticut, Rhode Island, Vermont, New Hampshire and part of Maine and also interconnected to the Pennsylvania, New Jersey and Maryland ("PJM") system.

Interconnection transmission capabilities between Ontario and these interconnected markets are subject to physical limitations that are additionally impacted by seasonal variations. Weather and physical aspects of the transfer of power such as loop flows, resulting from the physical movement of power on the interconnected transmission grid, can also limit transmission capability and scheduling. The normal limits of the interconnected transmission capabilities between Ontario and the interconnected markets through inter-ties are as follows:

Ontario Inter-Tie Capabilities with Interconnected Markets

(Source: IMO 18-month Outlook, January 6, 2003)

Interconnection	Limit (MW) Flows Out of Ontario	Limit (MW) Flows Into Ontario
Manitoba – Winter*	275	324
Manitoba – Summer*	275	324
Minnesota[3]	140	90
Québec North – Winter*	110[4]	84
Québec North – Summer*	95[5]	65
Québec South (East and Ottawa) – Winter*	760	1,385
Québec South (East and Ottawa) – Summer*	740	1,385
New York St. Lawrence	400	400
New York Niagara (60 Hz and 25 Hz) – Winter*[1]	1,000 – 2,000	1,200 – 1,500
New York Niagara (60 Hz and 25 Hz) – Summer*[1]	700 – 1,800	1,000 – 1,200
Michigan – Winter*[2][3]	1,800 – 2,200	1,200 – 1,700
Michigan – Summer*[2][3]	1,700 – 2,100	

* Summer limits apply from May 1 to October 31. Winter limits apply from November 1 to April 30.

Notes:

(1) Limits are based on thermal ratings and 75% of pre-load. Summer limits are based on 0-4 km/hr wind speed and 30 Deg. C ambient temperature. Winter limits are based on 0-4 km/hr wind speed and 10 Deg. C ambient temperature.

(2) Limits are based on thermal ratings and 75% of pre-load. Summer limits are based on 0-4 km/hr wind speed and 35 Deg. C ambient temperature. Winter limits are based on 0-4 km/hr wind speed and 10 Deg. C ambient temperature.

(3) For day-to-day operations of the interconnection, limits are based on ambient conditions such as wind speed, temperature and pre-loads.

(4) Limit based on 0-4 km/hr wind speed and 10 Deg. C or less ambient temperature.

(5) Limit based on 0-4 km/hr wind speed and 30 Deg. C or less ambient temperature.

In general, Ontario's inter-ties, subject to system conditions, have the ability to import approximately 21 TWh of electricity and export approximately 30 TWh of electricity annually.

Historically, OPG has sold a portion of its energy production into interconnected markets, with a majority of these sales to the northeast and midwest regions of the United States. The level of these sales varies from year to year from a high of 12.6 TWh in 1994 to a low of 3.0 TWh in 1998, with average sales of 3.9 TWh per year in the years 1997 to 2001. Prior to Market Opening OPG had exclusive access to the Ontario inter-ties. Since Market Opening, OPG must compete with others to buy or sell energy in and out of Ontario.

OPG's Customers

Ontario Customers

OPG must offer its production into the IMO-administered real time energy market, or spot market, in order to be dispatched by the IMO. This does not however apply to the small portion of the OPG's generation that is connected to a distributor, which OPG sells directly to the distributor. OPG also offers financial risk management products directly to end-users as well as to other wholesale parties in Ontario through bilateral contracts and is seeking to build on its existing relationships with Ontario customers in developing these product offerings. The nature and extent of this market has been reduced by the decision to set prices at 4.3 cents/kWh for what currently amounts to approximately 50% of the Ontario market. In addition, OPG and the IMO have entered into agreements for the supply of certain contracted ancillary services by OPG, including certified black start facilities, automatic generation control and reactive support/voltage control service.

Interconnected Market Customers

OPG's principal customers in the interconnected markets are U.S.-based investor-owned utilities as well as wholesale market participants active in the regions around Ontario, that purchase and sell power on a wholesale basis. Over the past 18 months, the wholesale markets for electricity and natural gas have seen reduced liquidity arising from the various events that have disrupted the markets. The wholesale market has faced unprecedented issues associated with liquidity, credit, accounting treatment, pricing and credibility, including the collapse of Enron and issues with the California market.

In order to re-establish confidence in the market, various regulatory initiatives and undertakings by self-regulatory organizations intended to improve disclosure and trading practices are underway. OPG is participating in these initiatives and adopting new practices where appropriate.

With respect to transactions in the U.S. interconnected markets, OPG is a full participant in the competitive wholesale power market administered by the NYISO and has been actively selling and purchasing energy in the NYISO day-ahead and hourly markets since November 1999. OPG is also a member of the Midwest Independent System Operator (MISO) and entitled to purchase transmission services in their market area.

OPG has entered into various master agreements with a wide range of counterparties pursuant to which it can transact for the purchase and sale of electricity in the U.S. northeast and midwest or trade financial derivative products. OPG's ability to transact under these agreements is limited by various factors such as the creditworthiness of the counterparty. OPG, through its U.S. subsidiary, has recently obtained the appropriate FERC authorization to sell at market-based rates. As a result, OPG is able to purchase transmission services and is able to transmit energy to buyers not directly connected with the Ontario electricity system at the U.S. border. This authorization allows OPG to buy its own transmission rights and to make purchases and sales of electricity, either sourced in Ontario or elsewhere, directly to wholesale or retail customers in the United States at market-based rates. This authorization will increase OPG's access to the U.S. market, beyond the NYISO and the Ontario border. See *"Business of OPG – Regulation"*.

The Market Rules require parties wishing to export electricity from Ontario to purchase energy from the Ontario spot market in order to sell it to export customers. The OEB has ruled that such export transactions should be charged a fixed transmission usage fee of $1/MWh, in addition to applicable IMO fees and uplift charges (including congestion charges internal to Ontario), all of which in general are expected to aggregate approximately $6/MWh (although it may be higher or lower in any given hour). Market participants can trade transmission rights

to provide a hedge against the possibility that there is congestion when importing and exporting electricity and their bid has not been accepted by the IMO. See *"Background – Ontario's Electricity Market – The IMO-Administered Wholesale Markets – The IMO Financial Markets"*.

Competitive Environment in Ontario

Market participants licensed by the OEB have participated in the IMO-administered markets since Market Opening. The spot market evolved quickly. In May 2002, there was a limited number of active participants. By June 2002, Ontario participants and other market participants from Québec, Michigan and New York were active in and bidding competitively. The energy market was particularly active due to above normal temperatures during the summer and early fall of 2002. Ontario imported approximately 4,000 MW during the summer of 2002. OPG believes that its cost of generation is, on an average short-run marginal production cost basis, lower than that of most other generators within Ontario and in many of its U.S. interconnected markets, although higher than generators in Manitoba and Québec.

In a competitive market, a variety of factors could influence OPG's low-cost position, such as the need for further investment in OPG's fossil generating facilities to comply with increasingly stringent limits on air emissions. In addition, notwithstanding OPG's overall low-cost position, OPG's peaking operations are less cost competitive and in addition other generators could offer power at prices below their full production costs in order to transact in Ontario or in interconnected markets, with the result that OPG generates less electricity than anticipated.

The total amount of electricity that was generated within Ontario in 2002 was approximately 150.0 TWh. Approximately 6.9 TWh of electricity was imported into Ontario and 3.7 TWh was exported in 2002. These transactions allowed Ontario's consumption of 153.2 TWh of electricity to be met. The total transmission and distribution losses associated with delivery of this electricity to Ontario customers was approximately 6.4%, or approximately 9.8 TWh.

OPG sees competitive pressures in Ontario from a variety of sources, including:

- *Companies which control generation capacity formerly controlled by OPG.* Decontrolled facilities do not tend to set prices in the IMO-administered markets. The Mississagi River system stations, however, which are no longer owned by OPG, do more directly compete with OPG to sell electricity to the IMO-administered markets;

- *Intermediaries that offer new products and services, including financial risk management products.* Intermediaries compete with OPG to sell energy products to end-users in Ontario by aggregating third party supply (domestic and imports) and spot-market purchases and by offering bundled value-added energy services or financial risk management services;

- *Imports of energy from the interconnected markets into Ontario.* Intermediaries and other parties compete with OPG for opportunities to import energy from outside Ontario. There are, however, limits to the amount of energy that can be imported into or exported from Ontario due to physical and seasonal limits on the capacity of transmission inter-ties between and within jurisdictions;

- *Generation by new independent power producers in Ontario.* Whether new capacity will be built will depend on a number of factors, including actual and anticipated price levels and demand for electricity and natural gas, the ability of parties to finance and structure economic transactions, technological advances and environmental and other regulatory developments; and

- *Self-generation by customers.* Interest in self-generation, or cogeneration, for load displacement by medium and large industrial and commercial customers is expected to continue, particularly if they have a large requirement for steam.

Commercial Strategy

OPG and other market participants are actively competing in the new Ontario energy market. OPG has developed bidding strategies for sales into the IMO market and is also building and maintaining its existing

relationships with wholesale energy customers in Ontario through enhanced communication and education programs.

All of OPG's energy production is offered into the IMO-administered market in order to be dispatched at the spot market prices. The largest part of OPG's revenue is derived from this source. A significantly smaller but growing portion of revenue will be earned through the sale of new products and services designed to help customers better manage their energy needs. OPG also buys energy from and sells energy into other markets, such as the NYISO, depending on market conditions.

OPG has developed and is actively marketing new customer focused financial products and energy-related services to Ontario industrial and commercial customers. Specifically, a portfolio of risk management products and supporting services for bilateral transactions, such as forwards, swaps and load–following bilateral products, billing, reporting and verification services, Green Power and energy management products like EnVision, which permits customers to measure and manage energy use, have been developed to meet customers' needs. New information systems and enhanced or redesigned business processes and operations, such as energy trading and risk management operations are being implemented to ensure that OPG possesses the resources, required skills, corporate culture and customer service focus which are critical to its success in the competitive market.

OPG's goal is to be a leading supplier of bilateral financial risk management products to selected wholesale and large and mid-size retail customers in Ontario and interconnected markets. OPG recognizes that its success in offering financial risk management products and services is predicated on a variety of factors including: the impact of government regulation on the marketplace, sophisticated product structuring and risk management skills in order to correctly price and manage complex structured products; marketplace relationships and brand equity to facilitate customer acquisition and retention and superior understanding of customer needs in order to structure energy solutions, including associated services, which best meet customer needs, as well as the capability to deliver such solutions. OPG recognizes that traditional segmentation based on size, industry category or type of business is not fully indicative of customer behaviour in a competitive market. In light of these market realities, OPG has taken a focused approach in targeting markets and customers for sales of OPG financial products and services based on those customers' expressed need for energy solutions. OPG will continue to invest resources in developing its trading, risk management and power marketing capabilities to position itself for success in Ontario and growth into interconnected markets.

Over time, customer expectations and demand for risk management products will evolve as some customers seek more complete customized solutions and others shift to self-manage their price and volume risks and deal directly with trading desks. Given these market dynamics, OPG anticipates the market for bilateral financial transactions in Ontario will fluctuate significantly during the first five years after Market Opening. Maintaining a strategic level of flexibility in markets, products and services is critical for OPG's success in these transactions in order to adapt to the high degree of uncertainty in the future environment. This in turn is impacted by factors such as regulatory change, OPG decontrol activities, the resultant level of rebates to customers under the market power mitigation framework, spot market price volatility, customers' price-risk tolerances and changing purchasing preferences of OPG customers.

Generation Operations

Overview

OPG's portfolio of generating facilities as of December 31, 2002 consisted of 22,211 MW of net in-service capacity comprised of 6,923 MW of hydroelectric capacity, 9,700 MW of fossil capacity and 5,588 MW of nuclear capacity (excluding the facilities leased to Bruce Power), plus further nuclear installed capacity of 2,060 MW that is currently laid up. This represents approximately 31.1%, 43.7% and 25.2%, respectively, of OPG's total generation capacity. OPG's nuclear stations and some hydroelectric generating plants are used primarily to provide base load capacity as they have very low marginal operating costs and, in the case of nuclear plants, are not designed for frequent variations in production level to meet peaking demand. Hydroelectric and fossil plants provide the bulk of OPG's intermediate capacity and peaking capacity.

Under the terms of its generation licence, OPG has committed to decontrol at least 4,000 MW of fossil net generating capacity within 42 months after Market Opening (1,000 MW of which can be substituted with

hydroelectric net generating capacity) and to reduce its effective control over generation capacity in Ontario to 35% or less of the electricity supply options in the Ontario market within 10 years of the beginning of Market Opening. To meet these requirements, OPG has decontrolled certain of its assets and will pursue decontrolling others. To date, it has leased the Bruce A and B nuclear generating stations to Bruce Power effective May 2001 and has sold the Mississagi hydroelectric plants (488 MW) to Mississagi Power Trust for $342 million effective May 2002.

Hydroelectric Operations

Hydroelectric generating stations use the potential energy of water to drive hydraulic turbines that generate electricity. OPG's hydroelectric stations provide one of OPG's competitive advantages: a reliable, low-cost source of renewable energy that is air emission-free. Through significant capital reinvestment, station automation, efficiency improvements and effective plant maintenance, OPG's hydroelectric plants have low operating and maintenance costs. OPG's hydroelectric plants are very competitive with generation in OPG's regional market area.

Generating Facilities

Generally, hydroelectric stations are grouped geographically and are operated on a river system basis rather than as stand-alone units. OPG's 65 hydroelectric generating stations (which includes 29 green energy stations), comprising 6,923 MW of capacity, and associated 232 dams are located on 26 river systems in Ontario.

Five Year Hydroelectric Capability, Capacity and Generation

	1998	1999	2000	2001	2002
Capability Factor (%)	90	91	92	93	92.6
Net Capacity Factor (%)	49.8	52.9	54	53	53.7
Net Energy (TWh)	31.9	33.6	34.0	33.7	34.3[1]

Note:
(1) Net energy in 2002 does not include electricity generated by the Mississagi River hydroelectric stations after May, 2002, when they were sold by OPG.

Capacity factor and energy statistics for hydroelectric facilities depend primarily upon the availability of water which is affected by the amount of precipitation and evaporation. In 1998, 1999, 2000 and 2001 the relatively low values for net energy and lower capacity factor were due to unusually low water availability resulting from greater than normal evaporation and lower than normal precipitation. In 2002, water availability increased, with the result that energy produced by OPG's hydroelectric stations increased.

A significant portion of OPG's hydroelectric production is produced at OPG's three largest stations located on the Niagara and St. Lawrence Rivers representing 43% of total hydroelectric capacity and 51% of hydroelectric energy production in 2002. In 2002, the two Sir Adam Beck stations on the Niagara River provided 1,949 MW of capacity, representing approximately 28% of OPG's hydroelectric capacity, and 11.2 TWh of energy production, representing approximately 32% of OPG's hydroelectric energy produced. On the St. Lawrence River, the R.H. Saunders station provided 1,045 MW, or 15% of hydroelectric capacity and 6.7 TWh, or 19% of hydroelectric energy produced in 2002.

Summary of Hydroelectric Generating Facilities and Performance (2002)

River System	Generating Station	Number of In-Service Units	Net In-Service Capacity (MW)[1]	% of Hydro-electric Capacity[1]	Net Energy (TWh)[1]	% of Hydro-electric Net Energy[1]	Original Unit In-Service Dates
Niagara Region							
	Sir Adam Beck I	10	497.8	7.2%	2.0	5.9%	1922 - 1930
	Sir Adam Beck II	16	1,450.8	21.0%	9.2	26.5%	1954 - 1958
	Sir Adam Beck PGS[2]	6	174.0	2.5%	(0.1)	(0.4%)	1957 - 1958
	DeCew Falls I and II	6	166.8	2.4%	1.2	3.4%	1898 - 1948
	Ontario Power[3]	0	0	0.0%	0.0	0.0%	1905 - 1912
St. Lawrence River							
	R.H. Saunders	16	1,045.0	15.1%	6.7	19.3%	1958 - 1959
Ottawa River							
	Otto Holden	8	243.0	3.5%	1.2	3.4%	1952 - 1953
	Chenaux	8	144.0	2.1%	0.7	2.0%	1950 - 1951
	Chats Falls[4]	4	96.0	1.4%	0.5	1.4%	1931 - 1932
	Des Joachims	8	429.0	6.2%	2.2	6.4%	1950 - 1951
Madawaska River		15	615.0	8.9%	1.0	2.8%	1917 - 1977
Abitibi River		9	501.0	7.2%	2.0	5.8%	1933 - 1963
Mattagami River		19	495.0	7.1%	2.2	6.5%	1911 - 1966
Mississagi River[5]		0	0	0.0%	0.4	1.3%	1950 - 1970
Other Rivers		116	1,066.0	15.4%	5.4	15.7%	1900 - 1993
Subtotal[1]		241	6,923[7]	100%	34.6	100%	
Water Transfers and Unit Rentals[6]					(0.3)		
Total (Net of Transfers)[7]		241	6,923[7]	100%	34.3	100%	

Notes:

(1) Capacity and production information is provided as at or for the year ended December 31, 2002. Net energy is the energy produced by the station less energy consumed by the station.

(2) During off peak periods reversible pump-turbine units at this station operate to pump water for storage in an elevated reservoir. During on peak periods water from the reservoir is run through the pump-turbine units to generate electricity for sale at higher prices. The outflow from the station rejoins the canal which supplies the main generating stations downstream.

(3) The Ontario Power station was removed from continuous service in 1999 as a result of the sale of the site on which the station's power distribution facilities were located. No decision has been made regarding the reactivation of this station to full service.

(4) Chats Falls is an eight-unit station, with four units owned by OPG and four units owned by Hydro-Québec. OPG operates and maintains the station, with costs shared equally with Hydro-Québec. Figures reflect OPG's share of total capacity and net energy.

(5) The four Mississagi River stations (488 MW) were decontrolled in May 2002. The Mississagi station's energy production shown above is for the period from January 1 to May 17, 2002. The Mississagi station's capacity numbers are assumed to be zero for the calculation of OPG's total capacity as the stations were decontrolled in May 2002.

(6) Hydroelectric generation in 2002 is shown net of the impact of various agreements relating to (i) the diversion of water between Ontario and each of Manitoba and Québec and (ii) agreements with the New York Power Authority regarding rental of generation facilities, which were 0.3 TWh in the aggregate.

(7) Reported net in-service capacity has increased by 42 MW to reflect hydroelectric upgrades during 2002.

OPG's hydroelectric generating stations range in age from nine to over 100 years and are, on average, the oldest assets in its power generation portfolio. Although there is a link between the age of a facility and the capital investment required to maintain that facility, age does not establish an upper limit on the expected useful life of hydroelectric facilities and dams, as regular maintenance and the replacement of specific components typically extend hydroelectric station service life for very long periods.

Facility Planning

OPG employs a portfolio approach to facility planning and maintenance and has grouped its 65 hydroelectric plants into five asset classes which have similar characteristics. Condition assessments are performed to determine future expenditures for each facility, followed by facility life cycle plans (on an as-needed basis). This planning approach is designed to identify necessary capital, operating and maintenance expenditures for each facility in order to prioritize and optimize facility investment within constraints imposed by technical, financial and regulatory requirements and system conditions. Outages are scheduled so as to minimize production losses due to unutilized water and to ensure unit availability during high water availability and market demand.

In the early 1990's, OPG began installing and replacing equipment that enables the remote control and monitoring of OPG's hydroelectric generating facilities. These modifications were designed to increase the efficiency of hydroelectric operations by reducing the number of staffed control rooms from 18 to eight, reducing control system failures and increasing the amount of information available for production planning. OPG now controls all of its hydroelectric generating stations through eight control centres. Work is underway to automate the Chats Falls Generating station on the Ottawa River so that it will no longer require a separate control centre. The automation project is expected to be completed by the end of 2003 and will reduce the number of control centres from eight to seven. Measures have been taken to ensure safety is not compromised. See "*Business of OPG - Health and Safety*".

Since 1990, OPG has refurbished and upgraded several of its hydroelectric facilities which has helped increase its hydroelectric capacity. This reinvestment program is continuing, with approximately $300 million expected to be spent over the next five years.

Water Payments

Hydroelectric generation requires ongoing access to an adequate water supply. OPG's rights to use the water at its hydroelectric stations are established through various international treaties, federal and provincial legislation and the common law. Other related operating rights are contained in leases, licences and agreements with the Federal Government, the Province, neighbouring provinces, municipalities, other utilities and other water users. See "*Business of OPG - Regulation – Water Rights*".

OPG makes payments ("water rental payments") for the use of Crown lands. These consist of gross revenue charges (the water rental portion) – *see "Business of OPG – Relationship with the Province and Others – Special Charges on Hydroelectric Generating Stations"*, calculated based on electricity produced at the relevant facility that results from the use of water. Most of OPG's hydroelectric stations pay gross revenue charges. Other stations are covered by separate agreements with various parties with payments made to the various parties having jurisdiction over those stations according to the terms specified in such agreements. The Federal Government receives rental payments for stations on Federal canals and waterways; the St. Lawrence Seaway Management Corporation receives lease payments in respect of water transported through the Welland Canal; and the Government of Québec receives payment for sites that span the Ottawa River. OPG has ten stations for which no water rental payments are made, as there are no Crown leases related to these stations. OPG's aggregate water rental payments including the water portion of the gross revenue charges in respect of 2002 were approximately $127 million for all of its hydroelectric stations. Of this amount, approximately $116 million is the portion paid under the gross revenue charge regime. The remaining balance of $11 million is for water rental payments made to various agencies, including the Federal Government and the Province of Québec.

Water Management

The physical availability of water is affected by variations in precipitation and evaporation. OPG uses hydrological and meteorological data to manage head, flow and water storage and to schedule water use in a manner which minimizes unutilized water flow. OPG's water management strategy is to optimize available water while meeting legal, environmental and operational requirements. Safety requirements are also an important aspect of water management, as evidenced by the tragic accident that occurred at OPG's Barrett Chute GS hydroelectric facility in June, 2002. Since this accident, OPG has enhanced its water management procedures to better ensure that safety considerations are appropriately addressed as part of OPG's water management strategy. See "*Business of OPG – Health and Safety – Public Safety*".

Dam Safety Program

OPG operates at a total of 240 dams; 232 dams in connection with hydroelectric generation and eight dams associated with the operation of its fossil generating stations. OPG recently reviewed its dam inventory and is conducting a variety of safety assessments. The review considered various criteria, including the size and function of the structures relative to the definition of a dam under the *Lakes and River Improvement Act* (Ontario). OPG's dams are operated and maintained in a manner that meets or exceeds safety guidelines published by the Canadian Dam Association. None of OPG's dams have failed in over 90 years of operation.

In 1986, OPG voluntarily established a dam safety program designed to ensure the safe and reliable operation of its dams and related facilities. OPG is one of the first dam owners in Canada to have developed and implemented a dam safety program. The dam safety program requires regular monitoring and inspections, maintenance and dam improvements where necessary. A review conducted by the Association of State Dam Safety Officials in 1997 concluded that OPG's program is effective, well-managed and contains all necessary elements. Approximately $75.8 million has been spent since 1988 on dam improvements and OPG plans to spend approximately $60 million over the next five years on upgrades and major maintenance as part of its dam safety program.

The Ministry of Natural Resources (Ontario) (the "MNR") has announced its intention to implement dam safety regulation under the *Lakes and Rivers Improvement Act* (Ontario). In September 1999, the MNR released a draft of its proposals for comments. Discussions regarding these proposals have taken place between MNR staff and various stakeholders, including OPG. The proposals have changed significantly since 1999 and the MNR is still evaluating and amending the proposals. It is, therefore, difficult to determine the specific impact of this proposed regulation on OPG, however, if the proposals were enacted as currently drafted, OPG would need to seek alternate methods to satisfy the Province. This is in part because the proposals include classification and design flood criteria that are different from the Canadian Dam Association criteria used by OPG. The MNR is aware that it will not always be feasible or reasonable for owners of existing dams to physically upgrade all dams that do not strictly meet the new criteria. The proposed regulations, therefore, allow owners of dams to submit a "Dam Safety Management Plan" to the MNR. These plans can include measures to enhance safety by means other than full structural upgrades and therefore would be significantly less costly than strict compliance with the proposed design flood criteria.

It is expected that the status that the OPG Dam Safety Program has achieved in the industry will allow, in most instances, the option of submitting Dam Safety Management Plans as a means of managing any residual risks associated with the operation of the structures. The feasibility and acceptance by the MNR of Dam Safety Management Plans will be subjective and can only be addressed on a case-by-case basis. OPG believes, however, that in most cases, it will be able to develop Dam Safety Management Plans that will be acceptable to the MNR.

Hydroelectric Station Decontrol

In May 2002, OPG completed the sale with Mississagi Power Trust of OPG's four hydroelectric stations on the Mississagi River, located approximately 70 km east of Sault Ste. Marie. The four stations, Aubrey Falls (162 MW), G.W. Rayner (46 MW), Wells (239 MW) and Red Rock Falls (41 MW), provide net in-service capacity of 488 MW and total average annual energy (averaged over a 30 year period) of 0.7 TWh.

Potential Expansion and Development at the Beck Site

Due to the design of some of the Niagara River generating stations, OPG does not currently have the mechanical capability to efficiently use all of the water available to it at that location. OPG mitigates the impact of these limits through a capacity rental arrangement with the New York Power Authority pursuant to which the parties share additional power generated by the New York Power Authority using OPG's water rights.

OPG has evaluated a number of alternatives to maximize its use of available water on the Niagara River. In 1998, provincial environmental assessment approval was granted for the Niagara River Development Project which, if undertaken, would consist of two new diversion tunnels extending from the Niagara River upstream of Niagara Falls to the Sir Adam Beck site, a powerhouse and associated transmission facilities.

The first part of the project, including construction of one of the diversion tunnels, would take approximately four years to complete. This project would not increase capacity but would result in OPG being able to produce more electricity from its existing Sir Adam Beck generating facilities. It would also permit OPG to repair the existing canal without having to schedule a planned outage at the station. The Government has recently encouraged OPG to pursue this tunnel project.

The construction of a second tunnel and a new generating station, would require approximately five years to complete and is estimated to cost in excess of $1.2 billion. The Government recently announced that the Ministry of Energy will study the feasibility of this project.

Fossil Operations

Fossil generating stations burn coal, oil or natural gas to heat water and create steam, which is used to drive turbines that generate electricity. OPG's fossil stations are a key component of OPG's overall portfolio. Fossil stations provide a flexible source of energy, as the stations may be taken on-line and off-line relatively quickly and without significant additional cost. Fossil stations may be deployed during periods of intermediate and peak demand or as a base load energy source to accommodate variations in the balance of the generating portfolio due to either planned or unplanned outages within the fleet. Through major investment in pollution control technologies, emission rates of oxide of nitrogen ("NO_x") and sulphur dioxide ("SO_2") from OPG's fossil plants have been substantially reduced. Continued investment to meet prospective Ontario and U.S. regulatory standards will bring further reductions in emission rates and in actual emissions. Regulations enacted by the Province set new emission caps for OPG's fossil stations commencing in 2002 and further limited SO_2 and NO_x emissions. To meet these caps over the next five years will require additional investment by OPG in emission control technology and new fuelling strategies. See *" Business of OPG – Environmental Matters – Management of Air Emissions – Fossil Operations"*.

Generating Facilities

OPG currently owns and operates six fossil stations. A total of 23 fossil generating units were in-service during 2002 with a combined net in-service capacity of approximately 9,700 MW, representing approximately 43.7%, based on of OPG's total in-service capacity in 2002 of 22,211 MW (i.e. excluding Pickering A, which was laid up and the Bruce and Mississagi River stations which were decontrolled). Coal-powered generating units located at Nanticoke, Lambton, Lakeview, Thunder Bay and Atikokan account for approximately 7,560 MW of in-service capacity. Dual-fuelled (i.e. capable of burning either oil or natural gas) generating units at Lennox account for approximately 2,140 MW of in-service capacity.

Five Year Fossil Capability, Capacity and Generation

	1998	1999	2000	2001	2002
Capability Factor (%)	74.4	68	76	71	76
Net Capacity Factor (%)					
Coal	51.8	51	62	56	54
Oil/Gas	6.5	12.3	6.4	16.7	16
Net Energy (TWh)	34.2	36.1	42.4	40.2	39.6

The increase in fossil capacity factors and total energy produced between 1998 and 2002 was due in part to increased coal-fired generation being required to compensate for declines in nuclear generation from the lay-up of units under the nuclear recovery plan. The two units at Lambton and the eight units at Nanticoke, each of which has been equipped with scrubbers, have provided most of this additional fossil generation. In order to meet the increased production demands on fossil generating units and still meet all regulatory requirements, a number of emission reduction initiatives were implemented. These included increasing the use of low-sulphur fuels and capital investments to reduce NO_x emissions. For example, in order to reduce OPG's NO_x emissions, approximately $90 million was spent between 1999 and 2001 on completing the conversion of units at Lennox to gas, the installation of low NO_x burners at Lambton, Nanticoke and Lakeview and the use of computer control to reduce NO_x emissions at Lambton and Lakeview. In addition, OPG is in the process of installing selective catalytic reduction equipment, which would significantly reduce NO_x emissions, on two units at the Nanticoke generating station and on two units at the Lambton generating station, at a cost of approximately $285 million. These installations are expected to be completed by the end of 2003. See *"Business of OPG – Environmental Matters – Management of Air Emissions – Fossil Operations"*.

Summary of Fossil Generating Facilities and Performance (2002)

Station	No. of In-Service Units	Net In-Service Capacity (MW)[1]	% of Fossil Capacity[1]	Net Energy (TWh)[1]	% of Fossil Net Energy[1]	Original Unit In-Service Date(s)	Estimated Retirement Date[2]
Nanticoke[3]	8	3,920	41	22.2	56	1973-1978	2015
Lambton[3]	4	1,975	20	9.9	25	1969-1970	2010-2020[4]
Thunder Bay[3]	2	310	3	1.5	4	1981-1982	2021
Atikokan[3]	1	215	2	0.8	2	1985	2025
Lakeview[3][5][6]	4	1,140	12	2.4	6	1962-1969	2005
Lennox[5][7]	4	2,140	22	2.8	7	1976-1977	2016
Total	23	9,700	100	39.6	100		

Notes:

(1) Capacity and production information is provided as at or for the year ended December 31, 2002. Net energy is the energy produced by the station less energy consumed by the station.

(2) Estimated retirement date is based on the average in-service date of units at the station and an estimated service life of 40 years except as noted.

(3) All units are coal-fired.

(4) Service lives for Lambton units 3 and 4 have been extended to 50 years as a result of extensive plant rehabilitation.

(5) Four additional generating units at Lakeview representing approximately 1,100 MW of power capacity were permanently taken out of service in 1992 as surplus capacity. A Provincial regulation requires Lakeview to cease burning coal by April 2005.

(6) Lennox units are dual-fuelled (oil/natural gas).

Fossil Station Decontrol

In response to a request from the Minister, OPG accelerated the planned decontrol of approximately 3,800 MW of fossil capacity, at Lakeview, Lennox, Thunder Bay and Atikokan. Lakeview has operated mainly as an intermediate to peaking plant and is required by regulation to cease burning coal by April 2005. Lennox, converted to dual-fuel, has operated predominately during peak periods. The Thunder Bay and Atikokan facilities have historically been operated as either base load or intermediate capacity facilities. OPG received indications of interest in all of these facilities, including a formal offer to purchase Thunder Bay and Atikokan. However due to market conditions and other factors, no transactions have been concluded. The assets are still available for decontrol, however the prospects for a successful transaction are likely to be influenced by a variety of factors including limited access to the capital markets, an excess supply of generating assets in the marketplace and the environmental regulatory framework.

Facility Planning

OPG's facility planning approach is designed to identify necessary capital, operating and maintenance expenditures for each facility in order to optimize returns from plant reinvestment within constraints imposed by technical, financial and system requirements as well as regulatory and voluntary emissions limits.

Large temperature and pressure variations experienced during cycling operation (i.e. stopping and starting the units frequently) of fossil units to meet system peaks cause more mechanical wear than continuous operation. For example, between 1995 and 1997 OPG's fossil stations were used primarily for peaking loads. There was, however, an excess of capacity in Ontario, so forced outages did not have a significant impact on OPG's ability to provide capacity to meet Ontario demand. As a result of the lower economic impact of outages, OPG generally focused on corrective rather than preventative maintenance for these stations, thereby avoiding extraordinary costs that OPG might otherwise have incurred to reduce the duration of outages. With increased usage of the fossil generating stations due in part to the lay-up of the Pickering A and Bruce A nuclear generating stations, increasing fossil capability has been an OPG priority, resulting in additional preventative maintenance activities and reduced outage periods.

OPG has recognized, and carries on its balance sheet, a provision to cover future costs of decommissioning and dismantling each fossil station. This provision is valued at approximately $96 million at December 31, 2002 and is not currently funded. Approximately $27 million of these decommissioning costs are associated with two plants, Nanticoke and Lambton, and $33 million for Lakeview. In establishing this provision, OPG has used 50

years as the expected service life for the two Lambton units where scrubbers have been installed and 40 years for the other fossil units.

Occupational Safety

On October 15, 2002, an employee fatality occurred while cleaning the coal conveyor at OPG's Nanticoke fossil generating station. OPG immediately reviewed conveyor guarding at all of its coal generating stations. In addition, a review was initiated with the objective of minimizing the safety risks associated with the operation and maintenance of coal handling equipment. The review is ongoing and is expected to result in (i) procedural changes and enhancements to safety barriers surrounding coal handling equipment, and (ii) expenditures of approximately three and a half million dollars.

Fossil Fuel Procurement

Coal is the fuel used at all of OPG's fossil generating stations except Lennox. Fuel and related transportation costs in 2002 accounted for approximately 78% of the total production cost of OPG's fossil generation. In 2002, OPG's total fossil fuel and related transportation costs amounted to $1,133 million, 82% of which was for coal. Approximately 93% of these costs in 2002 represented purchases in the United States or denominated in U.S. dollars. OPG's fuel unit energy costs generally declined in the period from 1995 to 2000 as a result of declining commodity prices, increased supplier competition and equipment modifications that enable the facilities to burn a broader range of coal types, although this was somewhat offset by the declining value of the Canadian dollar relative to the U.S. dollar over the same period. The price of coal started to increase in the last quarter of 2000, peaking in the middle of 2001. Current prices, while lower than the peak, remain above pre-2001 levels. OPG's coal purchases are made pursuant to a variety of short and medium term contracts. As a result, OPG anticipates that the average cost of coal purchased by it in 2003 will be high relative to years prior to 2001.

Approximately 90% of the coal used at OPG's fossil stations in 2002 was shipped by way of the Great Lakes. OPG maintains a seasonal inventory of coal at each of its coal-fired stations that is sufficient to meet forecast energy requirements during the winter months, typically from the end of December to the end of March, when Great Lakes shipping lanes are closed.

OPG's fossil fuel costs are affected by various factors including the cost of transporting coal from the eastern and western United States and western Canada, the sulphur content of coals and by choices made in balancing supplier diversity, contractual flexibility, fuel type and fuel quality. OPG blends coal with a range of sulphur contents for use in units that are not equipped with desulphurization scrubbers.

Natural gas and oil are used as generation fuels at OPG's Lennox generating station. Approximately 13% of the volume of natural gas purchased in 2002 was purchased pursuant to a long-term supply contract. This supply is shipped by firm pipeline capacity from Alberta to Lennox. The rest of the natural gas requirements are fulfilled by spot market purchases in Ontario. In 2002, OPG's total purchases of natural gas cost approximately $126 million.

The residual fuel oil for OPG's Lennox generating station is purchased through short-term "spot" purchases for volumes of typically 40,000 to 80,000 cubic metres (250,000 to 500,000 barrels) at a time. OPG does not have any long-term oil purchase agreements in place. Because of the requirement for low sulphur oil (under 0.7% sulphur content), the oil is purchased from offshore sources; pricing is typically tied to published oil price indices based upon delivery at New York Harbour for the quality of oil purchased. Transportation of residual fuel oil to Lennox is accomplished through leased rail cars, from terminals in either Québec or New York. In 2002, these residual fuel oil purchases cost approximately $14 million.

Brighton Beach Venture

OPG has a 49.95% partnership interest in Brighton Beach Power L.P. ("Brighton Beach"), a limited partnership formed with ATCO Power Canada Ltd. (39.96%), ATCO Resources Ltd. (9.99%) and, the general partner of the partnership, Brighton Beach Power Ltd. (0.1%). The shareholders of Brighton Beach Power Ltd. are OPG (50%), ATCO Power Canada Ltd. (40%) and ATCO Resources Ltd. (10%). Brighton Beach is developing a 580 MW combined cycle gas turbine electricity generating facility on the site of the former J.C. Keith Generating

Station site in Windsor, Ontario. In September 2002, Brighton Beach completed a $403 million private bond and term debt financing for its facility. Construction of the project began in the first half of 2002 and the plant is scheduled to be in-service during the first half of 2004. Brighton Beach has entered into a tolling arrangement with Coral Energy Canada Inc. ("Coral") under which Coral will own and trade the electricity produced by the facility in return for the supply of gas and the fees payable under a tolling agreement. Coral's financial obligations are guaranteed by Coral Energy Holding. L.P. ("Coral L.P.") and Coral L.P.'s obligations are in turn guaranteed by Shell Oil Company.

Portlands Energy Centre Venture

OPG has a 49.95% partnership interest in Portlands Energy Centre L.P. ("Portlands"), a limited partnership formed with TransCanada Energy Ltd. (49.95%) and, the general partner of the partnership, Portlands Energy Centre Inc. (0.1%). The shareholders of Portlands Energy Centre Inc. are OPG (50%) and TransCanada Energy Ltd. (50%). Portlands will assess the viability of developing a natural gas-fuelled energy centre in the port area of downtown Toronto. An environmental screening process has been commenced. If environmental approvals are granted, all applicable agreements are satisfactorily completed and the project proceeds, the plan contemplates that, a 550 MW natural gas-fired, combined-cycle, co-generation facility would be constructed. Portlands and Enwave District Energy Limited have signed a letter of intent that could see Portlands supply steam to Enwave's district heating system.

Effective Generation Limits and Air Emissions

Prior to 2002, OPG's aggregate SO_2 and NO_x emissions were capped under O. Reg. 153/99 to 215 Gg annually and SO_2 emissions to 175 Gg annually. This regulation is still in effect. In addition, the Province has enacted an emissions trading regulation (O. Reg. 397/01) that (i) provides for additional reductions of SO_2 and NO_x emissions from the Ontario electricity sector beginning in 2002; and (ii) introduces and provides a framework for emissions trading. The regulation includes an Emission Trading Code which sets out the rules governing the Ontario Emissions Trading Registry and the allocation, creation, reporting, verification, trading and banking of both emission allowances and emission reduction credits.

The new regulation requires facilities that emit SO_2 or NO_x emissions to demonstrate to the regulators, on an annual basis, that the emission levels, taking into account the use of emission reduction credits, do not exceed the allowable SO_2 and NO_x emissions ("allowances"). The amount of SO_2 emission reduction credits used annually cannot exceed 10% of the SO_2 allowances. The amount of NO_x emission reduction credits used annually cannot exceed 33% of the NO_x allowances.

For each of 2002 and 2003, the emissions trading regulation applies only to Ontario's six major fossil facilities (i.e. OPG's Lakeview, Lambton, Nanticoke, Lennox, Thunder Bay and Atikokan generating stations). OPG receives an annual allocation of 153.5 Gg of SO_2 allowances and 35 Gg of NO_x allowances for distribution to these facilities. For each of these years, the Province has also set aside an additional 4 Gg of SO_2 allowances and 1 Gg of NO_x allowances (the "set-aside" allowances) as an incentive to Green Power and conservation projects. Any unclaimed set-aside allowances are provided to OPG.

From 2004, the new regulation will apply to the entire electricity sector in Ontario. With regard to SO_2, allowances will be allocated to those facilities in the sector that emit SO_2, at a total annual level of 153.5 Gg for the period 2004 to 2006 and at a reduced level of 127 Gg thereafter. Unused allowances and emission reduction credits may be banked for future use, or traded. The SO_2 set-aside allowances remains at 4 Gg as described above.

With regard to NO_x allowances, from 2004 to 2006, the NO_x emitting facilities in the electricity sector will be provided with 35 Gg of NO_x allowances annually, reduced to 27 Gg thereafter. Of these, Ontario's six major fossil facilities will receive a combined total of 25 Gg in 2004, 22.4 Gg in 2005, 21.1 Gg in 2006 and 17.0 Gg in 2007. The independent facilities will receive an allocation of 10.0 Gg in 2004, 12.6 Gg in 2005, 13.9 Gg in 2006, and 10.0 Gg in 2007. Beginning in 2008, the distinction between major facilities and independent facilities for NO_x allowance allocation purposes will cease to exist and all NO_x emitting plants will compete for the 27 Gg annual pool of NO_x allowances. The NO_x set-aside allowances remain at 1 Gg as described above.

Emission allowances under the emission trading regulation are summarized in the following chart. The "Other Fossil Generation" allowances apply to other generators in Ontario.

Ontario – Electricity Sector SO_2 and NO_x Allowances

	SO_2 Allowances (Gg)		NOx Allowances (Gg)			
Year	OPG Facilities	Total Ontario Electricity Sector	Lakeview GS	Other OPG Facilities[1]	Other Fossil Generation[1]	Total Ontario Electricity Sector
2002	153.5		3.9	31.1	N/A[2]	35.0
2003	153.5		3.9	31.1	N/A[2]	35.0
2004		153.5	3.9	21.1	10.0	35.0
2005		153.5	1.3[3]	21.1	12.6	35.0
2006		153.5		21.1	13.9	35.0
2007		127.0		17.0[4]	10.0	27.0

Notes:

(1) The allowances for OPG's Atikokan, Lambton, Lennox, Nanticoke and Thunder Bay facilities are expressed on an aggregate basis.
(2) No annual NO_x allowances limits. All Other Fossil Generation must respect other environmental regulations (e.g. Certificates of Approval) under the EPA.
(3) As of May 1, 2005, NO_x allowances from Lakeview will be part of the allowances allocated to Other Fossil Generation.
(4) OPG allowances in 2007 are based on 15.5 Gg in Pollution Emission Management Area (defined in O. Reg. 397/01 and includes the southern Ontario air shed) plus 1.5 Gg outside Pollution Emission Management Area, as specified in O. Reg. 397/01.

In 2002, OPG's fossil facilities generated 39.6 TWh of energy, resulting in 42.3 Gg of NO_x emissions (on an NO basis) and 147.2 Gg of SO_2 emissions. OPG has met the requirements of O. Reg. 153/99, and is in possession of the required emission allowances and emission reduction credits to satisfy the requirements of O. Reg 397/01.

The following table sets out certain air emissions from OPG's fossil generating facilities for the past five years, with reference to applicable regulatory limits or voluntary limits, SO_2 and NO_x allowances, emission reduction credits and total fossil energy production.

Five Year Fossil Production and Air Emissions

	1998	1999	2000	2001	2002
Net energy (TWh)[1]	34.2	36.1	42.4	40.2	39.6
SO_2 emissions (Gg)					
OPG emissions	143.0	142.1	164.1	149.0	147.2
Allowance Allocation[2]					153.5
Set Aside Allowances					3.9
Total Allowance Allocation					157.4
Total Allowances Retired[8]					138.1
Emission Reduction Credits Retired					9.1[7]
Total Allowances and Credits Retired					147.2
Regulatory Limit [3]	175.0	175.0	175.0	175.0	175.0
NOx emissions (Gg)					
OPG emissions	55.8	51.4	50.5	44.6	42.3
Allowance Allocation[2]					35.0
Set Aside Allowances					0.9
Total Allowance Allocation					35.9
Total Allowances Retired					31.8
Emission Reduction Credits Retired	N/A	N/A	12.5	6.6	10.5[7]
Total Allowances and Credits Retired	N/A	N/A	12.5	6.6	42.3
Regulatory Limit	See Note (3)	See Note (3)	See Note (3) and (4)	See Note (3) and (4)	See Note (3)
Total Acid Gas Emissions (Gg)	198.8	193.5	214.6	193.6	189.5
CO_2 emissions (Tg)					
OPG emissions gross	31.0	32.2	38.5	37.0	36.72
Emission reduction credits	N/A	N/A	12.5	See Note (6)	See Note (6)
Voluntary Limit (net)[5]	N/A	N/A	26.0	26.0	26.0

Notes:

(1) Net energy is the energy produced by the station less energy consumed by the station.

(2) Commencing in 2002 under O. Reg. 397/01.

(3) O. Reg. 153/99 continues to apply (in concert with O. Reg. 397/01), meaning that OPG cannot exceed the annual limit of 175 Gg of SO_2 using the combination of allowances and emission reduction credits permitted under O. Reg 397/01.

(4) OPG agreed with provincial government agencies to voluntarily cap its NO_x emissions, net of emission reduction credits used, at 38 Gg annually, commencing in 2000.

(5) For 2000 and beyond, OPG voluntarily committed to stablize its CO_2 emissions, net of emission credits used at levels equivalent to the 1990 level into the foreseeable future. At the end of 2002, OPG had firm and option contracts in place for over 17 million tonnes of greenhouse gas emission reduction credits.

(6) The timeframe for reconciliation of net CO_2 emissions in the period 2001 to 2007 has been extended to the end of 2007.

(7) The net emission reduction credits are shown here. The regulation requires that an additional 10% of emission reduction credits be retired for the betterment of the environment.

(8) Retired means used to meet regulatory requirements.

OPG has a number of options available to meet its NO_x emission limits without limiting the amount of electricity that OPG can generate and sell during the year. First, OPG has embarked on a program of installing emission control technologies on its fossil units, including selective catalytic reduction ("SCR") technology on two units at the Nanticoke station and on two units at the Lambton station by the end of 2003, at a cost of approximately $285 million. The combined emission improvements for the 4 SCR's are in the order of up to 12 Gg NO_x per year. In addition, OPG has also installed low NO_x burners on all units except Lennox and Thunder Bay. Further, OPG has the flexibility to use emissions trading to meet its regulatory commitments. With the development of an emission reduction trading program, OPG could, subject to an upper limit of one third of its allowance levels, obtain and use emission reduction credits to offset any NO_x emissions. It is anticipated that current levels of generation from the fossil plants controlled by OPG (in the 40 TWh range) could be sustained in the short-term through the use of emission reduction credits.

SO_2 emission rates are directly related to the sulphur content and heat content of the fuel burned. OPG has primarily used higher-cost low sulphur fuels to reduce SO_2 emissions. The conversion to dual-fuel (natural gas and

oil) generating ability of four oil-fired units at the Lennox station was completed in 2000 and contributes to the reduction of SO_2 emissions because sulphur is removed from the gas before it arrives at the station. The cost of converting the units to burn gas was about $30 million and the cost of the pipeline to supply the gas was $20 million. OPG installed SO_2 scrubbers on two units at the Lambton station in the mid-1990s, at a cost of approximately $500 million, to reduce the SO_2 content of the flue gas before it is emitted into the atmosphere. Consequently, OPG is well positioned to meet its regulatory requirements related to SO_2 emissions for the foreseeable future. For further discussion of the regulation of air emissions, see *"Environmental Matters – Management of Air Emissions – Fossil Operations.*

Nuclear Operations

Nuclear generation harnesses the energy released during controlled nuclear fission reactions to produce steam that is used to drive turbines to generate electricity. Nuclear generation has two main advantages: it is a relatively low marginal-cost production technology and it produces virtually no SO_2, NO_x, CO_2 or mercury. The latter advantage is increasing in significance as governments implement stricter air emission standards.

Nuclear stations have greater operational, maintenance, nuclear waste and decommissioning costs and have greater initial capital development costs than other generation technologies. This reflects the complexity of the technical processes that underlie nuclear power generation and the additional design and safety precautions that are taken to protect the public from potential risks associated with nuclear operations. Offsetting these cost factors is the relatively low cost of nuclear fuel compared with fossil fuel costs. OPG's nuclear fuel is supplied by Canadian-based manufacturers that process uranium ore from both domestic and foreign sources. In general, OPG's operational nuclear stations have a lower operating cost per megawatt-hour of electricity produced than fossil facilities.

OPG's nuclear generating stations were designed to function primarily as base load facilities, given their low fuelling cost. OPG's two in-service nuclear generating stations, each consisting of four units, provided approximately 36% of OPG's total production in 2002.

Generating Facilities

Energy produced at the nuclear generating stations operated by OPG has declined in absolute terms since 1998, primarily as a result of OPG entering into a long term lease of the Bruce A and Bruce B generating facilities to Bruce Power on May 11, 2001. The Bruce A units were laid up and the Bruce B units were producing approximately 20 TWh on an annual basis at the time of the lease.

OPG currently owns and operates the Pickering and Darlington nuclear generating stations. The four Pickering A units have been laid up since late in 1997 as a result of OPG's nuclear recovery plan. One of these units is in the process of being restarted. See *"Business of OPG – Generation Operations – Nuclear Operations – Pickering A Lay-Up and Restart"*.

Five Year Nuclear Capability, Capacity and Generation

	1998	1999	2000	2001	2002
Net Capability Factor (%)	77	81	79	82	86
Net Capacity Factor (%)	76	81	78	81	86
Net Energy (TWh)	59.9	61.4	59.8	47.7	41.9

Summary of Nuclear Generating Facilities and Performance (2002)

Station	No. of In-Service Units	Net In-Service Capacity per Unit (MW)[1]	Net In-Service Capacity (MW)	Capacity Factor[1]	Net Energy (TWh)[1]	% of Nuclear Net Energy[1]	Original Unit In-Service Dates	Estimated Operating Life[2]
Darlington	4/4	881	3,524	89.4%	27.5	66	1990-1993	2022-2025
Pickering A[3]	0/4[4]	515	2,060	0%	(0.1)	0	1971-1973	2011-2013[5]
Pickering B	4/4	516	2,064	79.9%	14.4	34	1983-1986	2013-2016
Total	8/12[4]		7,648	85.9%[6]	41.9	100		

Notes:

(1) Net capacity and production information is provided as at or for the year ended December 31, 2002 Net energy is the energy produced by the station less energy consumed by the station.

(2) The estimated operating life of each nuclear generating station is assumed to end when substantial capital expenditures are required to replace life-limiting components such as fuel channels and steam generators, typically after 25 to 30 years of operation. The estimated operating life of Pickering A is expected to be 40 years (see notes). The operating lives of these stations can be extended with substantial capital expenditures but OPG will incur these expenditures only if justified by prevailing economic, financing and market conditions. See "*Business of OPG - Generation Operations -Nuclear Operations - Operating Life Assessment*".

(3) 2,060 MW of capacity was removed from service as a result of the lay-up of Pickering A under OPG's nuclear recovery plan. See *"Business of OPG - Generation Operations -Nuclear Operations - Nuclear Recovery Plan"*.

(4) OPG is in the process of returning one of the Pickering A units to service. See "*Business of OPG - Generation Operations – Nuclear Operations – Pickering A Lay-Up and Restart*".

(5) OPG replaced the pressure tubes of Pickering A between 1984 and 1993 after the discovery of a design flaw. Thereafter, OPG extended the operating life estimate for Pickering A to 40 years because of these new pressure tubes and the condition of the existing steam generators.

(6) The percentage represents the average capacity factor for in-service units.

Nuclear Recovery Plan

Optimization of OPG's nuclear generation capacity has been an important part of OPG's strategic plan. OPG's nuclear generating stations performed well after they were initially brought into service. However, over the years, inadequate operational and maintenance practices contributed to declining nuclear production resulting from more frequent forced outages or extensions to planned outages. Maintenance backlogs grew and there were an increasing number of reportable events to the regulator, the Atomic Energy Control Board (now the Canadian Nuclear Safety Commission, "CNSC"), which in turn resulted in increased regulatory scrutiny. OPG implemented various recovery initiatives in the early 1990s to address these operating difficulties. These initiatives did not identify or deal with the underlying causes due to inadequate planning, co-ordination, resources and accountability.

As a result, in 1997, OPG engaged a team of independent nuclear recovery experts to assess its nuclear operations. This team utilized an enhancement of a methodology developed and used by the United States Nuclear Regulatory Commission to successfully identify and rectify fundamental operating problems at U.S. nuclear generating stations in the 1980s.

The team classified OPG's nuclear operations as "minimally acceptable". OPG's operational and maintenance activities were below industry standards and its management systems were not capable of ensuring that these activities were being planned and executed in a rigorous and cost-effective manner. The team found an organizational culture not focused on efficient and effective operation. In addition, the team found evidence of deteriorating equipment at each nuclear generating station and concluded that OPG was not repairing equipment promptly enough to prevent further deterioration. The team also found that OPG's inspection program for its steam generators was inadequate. The team concluded that existing safety margins were deemed sufficient to protect employees, the public and the environment but OPG would have to implement significant operational and management changes in order to avoid regulatory intervention and restore OPG's nuclear operations to industry-leading standards of safety and performance. The team determined that the design of the CANDU reactor was not a contributing factor to OPG's declining nuclear performance.

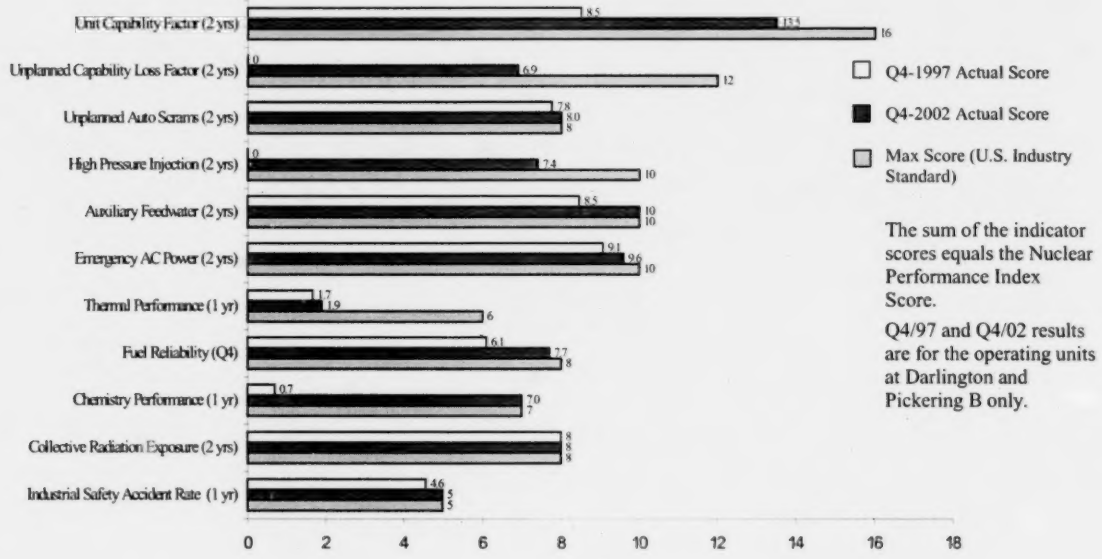
OPG's operational difficulties were not unique. The U.S. nuclear industry experienced similar problems in the 1980s, which were largely rectified through the adoption of enhanced operating practices and industry-wide knowledge-sharing practices which form the basis of the practices currently being implemented by OPG.

In conjunction with independent nuclear recovery experts, in the fall of 1997 OPG developed a comprehensive nuclear recovery plan to improve the operating performance of its nuclear generating stations over a seven year period. Under the plan, OPG is continuing to standardize its operations and implement initiatives to improve: accountability; management and operational control systems; maintenance and inspection programs; regulatory compliance; performance standards and employee training. OPG adopted a phased nuclear recovery strategy in order to focus qualified personnel and management resources on fewer units. As a result, the Pickering A station was placed in short term lay-up on December 31, 1997. This enabled OPG to focus its initial recovery efforts on the remaining eight nuclear generating units at the Darlington and Pickering B stations. Expenditures related to the nuclear recovery plan during the period from 1997 to 2004 are expected to total $1,145 million. See "*Business of OPG – Generation Operations – Nuclear Operations – Pickering A Lay-Up and Restart*".

As part of its nuclear recovery plan, OPG has adopted the standard nuclear performance index ("NPI") sponsored by the American members of the Institute of Nuclear Power Operators ("INPO") and the World Association of Nuclear Operators ("WANO"). The NPI quantifies the performance of nuclear generating stations with reference to eleven performance indicators, two-thirds of which are related to safety and one-third to production. OPG reports its results quarterly and annually to WANO. The performance of OPG's eight in-service units at Pickering B and Darlington for 1997 and the fourth quarter of 2002, compared to the maximum NPI score possible, are set out in the following chart:

Nuclear Performance Index

Comparison of Component Indicators



OPG establishes annual nuclear performance targets (some of which relate to the nuclear performance index described above). OPG met or exceeded 19 of its 26 key nuclear performance targets for 2002, including the targets for worker safety, employee development and plant reliability. The three most significant areas in which targets were not met were generation, moderate environmental regulatory infractions and financial performance. The main reasons these targets were not met were as follows: (i) the delay in restarting the first Pickering A unit resulted in OPG's overall generation target not being met, notwithstanding that generation targets were met at the Pickering B and Darlington generating facilities; (ii) in 2002, OPG's nuclear stations experienced a significant increase in the number of moderate environmental regulatory infractions primarily due to a small number of failures of OPG's monitoring practices. There were, however, no significant environmental releases in 2002 at OPG's

nuclear stations; and (iii) the financial targets for OPG's nuclear stations were not met due to the higher than budgeted expenditures related to the Pickering A return to service work and to planned outages at Pickering B and Darlington.

Pickering A Lay-Up and Restart

OPG is continuing with the safety and environmental upgrades and other refurbishment work that is required as part of the return to service of the four units at the Pickering A nuclear generating station. The aggregate expenditures on this return to service initiative as at the end of December 2002, which includes the cost of certain common operating systems for all four units, is approximately $1,200 million. Approximately two-thirds of these expenditures have been expensed.

The restart initiative, while continuing to make significant progress, has faced major challenges. The specified improvements and upgrades requested by the CNSC in OPG's licence application for restart were more extensive than originally anticipated and the overall implementation of the project is costing more and taking longer than initially planned. This is as a result of a variety of factors, many of which are implicit in a major refurbishment of this nature where the actual extent of many aspects of the project can only be firmly determined after work has progressed well beyond the initial stages. In part related to these factors, the engineering costs are significantly higher than anticipated and completion of engineering work has taken materially longer than planned, with a related impact on cost as well as scheduling and level of completion of work in the field. In addition, increased security requirements following September 11 have complicated the supply of labour and materials to the project. Further, there has been a higher than anticipated level of rework. As a result, costs have increased and the project is taking longer to complete than originally planned.

Work is progressing to allow for the first unit to be in-service by the summer of 2003. The additional cost to complete the first unit is estimated at approximately $150 million. There remain risks that could impact the cost and schedule of the return to service of the first unit. This includes the risk of additional construction and other discovery work that may be identified through the testing and commissioning process, additional challenges that may result from the first-time commissioning of a laid-up unit and various regulatory risks related to obtaining the required approvals.

OPG has commenced planning for the return to service of the second unit. The cost and schedule to return this unit to service are under review and will be estimated taking into account OPG's experience associated with returning the first unit to service. By the end of the second quarter of 2003 OPG expects to complete a detailed assessment of the timing and estimated costs to return the second unit to service. See *"Business of OPG – Corporate Strategy – Pickering A Return to Service"*.

Operating Life Assessment

The initial design life for OPG's nuclear generating stations was 30 years. OPG undertakes a comprehensive inspection and testing program in order to ascertain the physical condition of its nuclear generating assets. The condition of the major components is assessed using a variety of inspection techniques such as ultrasonic, visual and functional testing. These results provide engineers with an assessment of the condition of such components relative to original design. Repeated inspection or testing during planned outages is used to establish degradation rates. The experience of other nuclear operators is also taken into consideration. This information is used to update the life cycle management plans for major plant components. The life cycle management plans are a key input to OPG's business planning process. OPG's current operating life estimates for its nuclear generating stations are based on the results of this program to date and on the previous operating history of the stations. OPG will continue to analyze information on the physical condition of its nuclear generating stations and develop appropriate operational and maintenance activities.

As a key part of its nuclear recovery program, OPG has undertaken an ongoing program to assess the condition of key components of the system including its steam generators, fuel channels and feeder pipes. As a result of these programs, OPG has been better able to quantify equipment degradation status, such as the extent of steam generator tube corrosion, feeder tube wall thinning and pressure tube/calandria tube spacer location and

relocation issues. As of December 31, 2002, 72% of OPG's steam generators (with 76% of the tubes) had been inspected and the present condition of these components has been ascertained with a reasonable degree of certainty. On the basis of the steam generator program inspection results, periodic cleaning has been deemed necessary to slow down the degradation rates. OPG is currently implementing comprehensive operation and maintenance life cycle management plans at all operating stations aimed at enabling the steam generators to operate for the expected life of the station. A prognosis for the remaining life of each unit has been estimated and those at Pickering B will be most closely monitored.

Results from the fuel channel inspection program continue to support the current end-of-life projections for the fuel channels. Maintenance activities at Pickering B to reposition the support springs in the fuel channels started in 2002 and are planned to continue over the next several years to ensure that the end of life projections are achieved. The modular design of the reactors also allows for replacement of individual channels during planned outages, if required.

Feeder pipes are part of the piping system that carries hot water from the reactor to the steam generator. Thinning of feeder pipes occurs to varying degrees at all of OPG's reactors. This condition is most significant at the Darlington plant, but also affects the Pickering A and B stations to a lesser degree. Extensive inspections have been carried out to establish the current condition of the feeders. If the currently observed thinning rate at Darlington continues, this situation may require replacement of selected pipes before the projected end of life. Mitigation options are under development by OPG which may extend feeder pipe life and significantly reduce the thinning rate. The results of OPG's inspections to date indicate that even if such mitigation options are successful in saving 90% of the feeder pipes that are currently at risk, additional expenditures in the range of $50 – 100 million (for four units at Darlington) and one to two months of additional outage time per unit, will still be required over the next decade to deal with thinning feeder pipes. This strategy and its associated costs continue to be reviewed and revised as appropriate.

Cracking of feeder pipes has been experienced at a CANDU plant located outside Ontario. The affected sections of pipe were replaced and the unit returned to service. OPG has not experienced any feeder pipe cracking at any of its nuclear facilities but is carrying out inspections during regularly planned outages. OPG believes that feeder pipe manufacturing differences may make the feeder pipes at Pickering A and Pickering B less susceptible to this phenomenon.

CANDU Technology

All of OPG's nuclear generating stations use CANDU reactors. CANDU is a pressurized-heavy-water, natural-uranium power reactor first designed in the 1960s by a consortium of Canadian government agencies and private industry. All nuclear reactors in Canada use the CANDU technology. It is also the power-reactor product marketed by Canada abroad. CANDU reactors are currently operating in Ontario, Québec, New Brunswick, Argentina, Romania and South Korea and in China, one unit is in its initial start-up phase and one unit is under construction.

CANDU reactors are unique in their use of natural-uranium fuel and deuterium oxide, or heavy water, as both moderator to slow down the fission process and coolant within the reactor. The refuelling system is also unique in that CANDU reactors can be refuelled at full power. This is due to the subdivision of the core into hundreds of separate fuel channels each holding a single string of natural uranium fuel bundles, allowing for greater fuel efficiency. In contrast, U.S. reactors, which use enriched uranium fuel, must be shut down during refuelling which may require a planned outage of 15 to 30 days every 18 to 24 months.

Each CANDU unit is designed with a computerized reactor control system which controls reactor power and the transfer of heat generated in the fuel to the turbines. By changing the demanded power level to the control system, the unit operator can adjust the reactor power level and, therefore, electrical generation, from shut down to full output. The system design also permits on-line maintenance, with redundancy features to improve reliability. Although the normal control process systems are reliable and capable of shutting down the reactor, the stations have also been designed with separate and independent multiple fail-safe safety systems for fast reactor shutdown, emergency cooling and radiation containment. All of OPG's reactors, other than those at the Pickering A station, have two physically separate and independent systems designed to shut down the reactor within two seconds of being activated. Each of these systems is independent of the primary control systems and includes multiple sensors

for detecting emergency conditions. The first shutdown system consists of neutron absorbing rods suspended above the reactor, which would fall automatically into the moderator upon detection of an emergency condition. The second shutdown system contains a neutron-absorbing solution, which would be rapidly injected into the heavy water. The Pickering A reactors were originally designed with only one shutdown safety system, which utilized two different shutdown mechanisms. The primary shutdown mechanism consists of fast-acting neutron absorbing rods. An additional slower-acting shutdown mechanism, which drains the reactor moderator to a dump tank, is also present. An enhancement to the original shutdown system, which consists of an independent detection system, is being installed prior to the restart of Pickering A.

OPG's reactors also have an emergency core coolant injection system which would be activated in the event of a pipe break in the reactor coolant system. This system would inject ordinary water into the cooling system to ensure that coolant continues to circulate over the nuclear fuel bundles to prevent them from overheating. In addition, all of OPG's nuclear generating stations have a negative pressure containment system. Each reactor is enclosed in a thick-walled concrete containment building connected to a vacuum building by a large duct. If pressure in the containment building exceeds operating limits, pressure relief valves would automatically open and release any radioactive material into the vacuum building. The negative pressure within the vacuum building, together with steam suppression by a dousing system, would keep radioactive material safely contained within the vacuum building walls. Controlled venting, within permissible levels of release, would also be available for long-term pressure control through filtered-air discharge systems.

Regulatory Affairs

OPG's nuclear operations are heavily regulated. The Canadian Nuclear Safety Commission ("CNSC"), an agency of the Federal Government, regulates these operations under the *Nuclear Safety and Control Act* (the "NSC Act"). In addition, OPG is subject to the *Nuclear Liability Act* (the "NLA"). The NSC Act, which replaced the Federal *Atomic Energy Control Act* effective May 31, 2000, updates the prior legislation which had been adopted in 1946 and broadens certain powers of the CNSC to regulate nuclear operators. All construction requirements, equipment, safety systems and operating limits for OPG's nuclear generation stations are subject to the approval of the CNSC. OPG is required to provide routine reports to the CNSC, which continually monitors the safety performance of OPG's nuclear generating stations. See *Business of OPG – Regulation – Nuclear Regulation".*

Reactor Physics

The CNSC requires that OPG and other nuclear operators conduct safety analysis in order to license reactors for operation. One of the objectives of such safety analysis is to demonstrate that an unacceptable release of radioactivity will not occur in the event of a large break loss of coolant accident. In 1999, the CNSC requested OPG to use a new set of computer codes for performing such safety analysis. Analysis performed by OPG with the new codes indicated a reduction in the safety margins from those obtained with the old codes. OPG therefore introduced operational changes that have resulted in reductions in reactor power output (referred to as a "derate").

The reduced safety margins identified by the amended reactor physics codes have reduced OPG's operating margins and increased OPG's costs with respect to the operation of Darlington and Pickering A. All four units at Darlington continue to be derated to 98% of the maximum reactor power level. Modifications intended to allow the return of Darlington to 100% are planned for completion this year and safety analysis with the new codes in support of this increase has been submitted to the CNSC with a request to raise power as the modifications are completed in each unit. The CNSC is reviewing the submission. OPG has submitted a safety analysis with the new codes to the CNSC in support of operating the Pickering A units, when restarted, at 100% of the maximum reactor power level. However, in order to comply with the new operating limits specified by this analysis, reactor power in the Pickering A units may be restricted to as low as 96% of their maximum reactor power level. Current estimates indicate that Pickering B will not be derated as a result of the new analysis.

Ongoing work is being undertaken by OPG and other nuclear operators in an effort to restore operation at maximum power levels. This activity involves a combination of additional safety analysis, a redesign option study and proposing options for changing the licensing basis used for reactor regulation in Canada. The CNSC may require that OPG implement design changes to the derated nuclear reactors before permitting OPG to resume operation at maximum reactor power levels. Although a detailed evaluation of the costs associated with such potential design changes have not been completed, it is currently estimated that the cost associated with returning

Darlington to maximum reactor power is likely to fall in a range between $50 million and $100 million and will take up to five years to implement.

Nuclear Fuel Procurement

OPG has a varied portfolio of supply contracts for uranium concentrates with suppliers located in uranium-producing regions across the world. The contractual terms have been developed to mitigate price and supply risks. OPG uses one contractor to convert its uranium concentrates into uranium dioxide and has made arrangements with this contractor for an alternate conversion facility in the event the primary conversion facility cannot satisfy OPG's requirements. Price increases for uranium dioxide are limited by contractual terms.

OPG has entered a long-term contract with one independent manufacturer to process uranium dioxide into finished nuclear fuel bundles. Supply security risks are mitigated through provisions contained in the agreement, through the existence of an alternative qualified supplier with some available capacity and through the implementation by OPG of a strategy to increase OPG's inventory of finished fuel bundles such that OPG maintains a 12-month inventory of finished fuel bundles.

OPG believes there is adequate capacity available in each of these segments to accommodate the return to service of the Pickering A and other Canadian-owned CANDU reactors.

Ancillary Operations

Heavy Water Management

OPG's nuclear generating stations contain approximately 7,000 tonnes of deuterium oxide or heavy water (not including heavy water contained at the leased Bruce stations), which is required to operate the CANDU reactors. OPG also owns an additional inventory of approximately 1,200 tonnes of heavy water. OPG's heavy water was produced at two heavy water plants at the Bruce site between 1973 and 1997. One of these heavy water plants was demolished in 1993-1995; the other ceased operations in 1997. Permanent shut-down was completed by the spring of 1998. Demolition of the second plant and remaining common facilities is expected to be completed in 2005, subject to prior regulatory approvals. Follow-up environmental monitoring and site remediation is expected to occur over a period of at least three years after demolition. OPG believes that its inventory of heavy water will be sufficient to replenish supplies as a result of normal operating losses at its nuclear generating stations during the expected operating lives of the stations. If the operating lives of these stations are extended, additional supplies of heavy water may have to be purchased from third parties. OPG has in the past sold and intends to continue to sell, surplus heavy water.

Tritium Removal

Tritium is a radioactive substance that is released into the heavy water moderator of CANDU reactors as a by-product of the nuclear fission process. OPG owns a facility at its Darlington site that removes tritium from the heavy water used at its nuclear generating stations in order to control the occupational dose exposure to its staff and the release of tritium oxide to the environment. The facility will also be used to detritiate heavy water during the decommissioning of OPG's nuclear generating stations. Some tritium is sold to government-approved organizations for authorized commercial and health industry uses.

Divestment of Nuclear Safety Analysis Division

On September 12, 2002, OPG and NNC Holdings Limited of the UK concluded an agreement under which OPG transferred 150 scientists, engineers, technologists, managers and support staff, who perform nuclear safety analysis and assessments, to Nuclear Safety Solutions Limited ("NSS"), the wholly-owned Canadian subsidiary of NNC Holdings Ltd. Under this transaction, NSS acquired the resources and technology to provide nuclear safety services on a commercial basis to OPG, Bruce Power and possibly other customers.

Inspection Services Division

The Inspection Services Division, comprises in excess of 300 staff within the Nuclear Operations group, is responsible for certain inspection and maintenance services, principally in relation to pressure tubes and steam generators, performed mainly in OPG and Bruce nuclear power plants. OPG has initiated a process to potentially outsource its Inspection Services Division. A transaction, if any, should be completed during 2003.

Nuclear Waste Management and Decommissioning

As they operate, OPG's nuclear reactors produce used nuclear fuel bundles (high-level radioactive waste); other material that has come in close contact with the reactors but is less radioactive than used fuel, such as ion exchange resins and other structural material and reactor equipment, including pressure tubes (collectively, intermediate-level radioactive waste); and other material used in connection with station operation that is not highly radioactive, such as tools and protective clothing (collectively, low-level radioactive waste). OPG is responsible for the ongoing long-term management of these wastes. In addition, OPG will have to manage radioactive waste associated with decommissioning of its nuclear generating stations after the end of their useful lives. The handling and disposal of radioactive material in Canada is subject to Federal legislation. See *"Business of OPG – Regulation – Nuclear Regulation"*.

Federal Government Policy

There is no facility for the permanent disposal of nuclear waste currently in operation in Canada, nor has the CNSC licensed any such facility. Since 1978, Atomic Energy of Canada Limited ("AECL"), under the direction of the Federal Government, and OPG have been researching the concept of disposing of nuclear fuel waste in long-lasting containers that would be placed approximately 1,000 metres underground in stable granite rock ("deep geological disposal").

In July 1996, the Federal Government announced a policy framework to ensure that the disposal of radioactive waste would be carried out in a safe, environmentally sound, comprehensive, cost-effective and integrated manner. A Federal environmental assessment review panel (the "Seaborn Panel") reported to the Federal Government in March 1998 after a 10 year review of the deep geological disposal concept. The Seaborn Panel concluded that the technical safety of the deep geological disposal concept was adequately demonstrated for a conceptual stage of development but that broad public support had not been demonstrated. The Seaborn Panel recommended, among other things, the creation of an independent agency to manage used nuclear fuel, the establishment of a segregated fund (funded by producers and owners of radioactive waste) to finance disposal costs and the study of alternatives to the deep geological disposal concept.

As part of the response to the Seaborn Panel's report, the Federal Government enacted the *Nuclear Fuel Waste Act* ("NFWA"), which came into force in November 2002. The NFWA requires the owners of nuclear fuel waste in Canada to establish a waste management organization, incorporated as a separate legal entity, with a mandate to manage and coordinate the full range of activities relating to the long-term management of nuclear fuel waste. In response to the NFWA, in 2002 OPG and other Canadian nuclear waste producers incorporated the Nuclear Waste Management Organization (NWMO)/Société de gestion des déchets nucléaires (sgdn) (the "NWMO") with an Advisory Council. The NWMO will complete a study of the options available for the long-term management of used fuel by 2005, as required by the NFWA, with Federal Government direction on a long-term plan to follow. The NFWA also required the nuclear fuel waste owners to establish and make payments into trust funds for the purpose of funding the implementation of the long-term management plan. See *"Nuclear Operations – Nuclear Waste Management and Decommissioning – Provisions for Future Nuclear Related Costs"*.

Current Management Practices

Bundles of used nuclear fuel from OPG's reactors and leased reactors at the Bruce site are temporarily stored in water-filled pools known as "wet bays" at the nuclear generating stations, for a "cooling-off" period of at least ten years during which time their radioactivity is substantially reduced. Each nuclear generating station has sufficient capacity to store used nuclear fuel in wet bays corresponding to approximately 15 to 20 years of operation.

After bundles of used nuclear fuel have been stored for their cooling-off period and water-filled pools near their capacity, they are transferred from the wet bays to above-ground concrete canisters ("dry storage") at the corresponding nuclear station site. Currently, used nuclear fuel is in dry storage only at the Pickering site. Construction of a used fuel dry storage system at the Bruce site was completed in 2002. In-station modifications required to the Bruce B pools to support loading of used fuel into dry storage containers was completed by Bruce Power in 2002. Used fuel transfer from wet storage to dry storage at the Bruce site will commence in 2003. OPG is planning to establish dry storage facilities at the Darlington site by 2007.

OPG's low and intermediate-level radioactive waste is stored at its radioactive waste management facility at the Bruce site, the Western Waste Management Facility. This facility, which continues to be owned and operated by OPG following the decontrol of the Bruce stations, operates under separate licences issued by the CNSC. OPG plans that the low-level and intermediate-level radioactive waste produced by OPG's nuclear facilities and by Bruce Power at the Bruce A and Bruce B stations will continue to be stored at this facility and that its operations will be expanded as necessary.

OPG's current financial planning assumptions for purposes of funding of nuclear fuel waste and decommissioning liabilities are that a deep geological disposal facility for used nuclear fuel will be available in 2035 and a low-level radioactive waste disposal facility will be available in 2015. Intermediate level radioactive waste, depending on its radioactive content, will be co-disposed with low-level radioactive waste commencing in 2015 and with used nuclear fuel commencing in 2035. In August 2000, OPG submitted a management plan to the CNSC which revised the reference date for an in-service used fuel disposal facility from 2025, as included in the previous reference plans, to 2035. This plan was confirmed in communications between staff from the CNSC and OPG and forms part of the plans for nuclear waste management and decommissioning liabilities that have been submitted to the CNSC to meet requirements under the *Nuclear Safety and Control Act* (Canada) for a financial guarantee, which is expected to be established in 2003.

OPG has adopted a deferred dismantling strategy for the decommissioning of its nuclear generating stations. Under this strategy, OPG intends to defuel each station immediately after it has ceased operations and prepare the station for storage and monitoring. Thereafter, OPG intends to monitor the station for approximately 30 years, after which it will dismantle the station over a period of approximately ten years. This deferred dismantling strategy has been communicated to the CNSC through preliminary decommissioning plans for all of OPG's nuclear generating stations and operating licences have been issued based on, among other things, its review of this strategy. Financial guarantees required for decommissioning liabilities will also be based on this strategy.

Provisions for Future Nuclear-Related Costs

OPG's nuclear facilities commenced production in the early 1970s but until 1982 no accounting or funding provisions were made for liabilities related to the estimated future costs of its nuclear waste management and decommissioning programs. In 1982, Ontario Hydro began collecting provisions through its rates in amounts that, together with interest accumulated on provision balances, were calculated to cover all such future liabilities. These provisions, which were carried in Ontario Hydro's accounts at $2,344 million as at December 31, 1998, were not placed in a segregated fund but were used for general corporate purposes and therefore served to reduce borrowing requirements.

On April 1, 1999, the obligation for nuclear waste management and decommissioning was transferred to OPG. The responsibility for funding these liabilities is described in the Ontario Nuclear Funds Agreement between the Province and OPG. This agreement is to become effective as of April 1, 1999 upon execution of supplementary agreements for the custodianship and the management of the funds with the Province which is expected to occur in 2003. The key provisions of the Ontario Nuclear Funds Agreement are: (i) for OPG to establish two segregated funds, comprising a used fuel fund (to fund future costs of nuclear used fuel waste management) and a decommissioning fund (to fund the future cost of nuclear fixed asset removal and low and intermediate level waste management); (ii) for the OEFC to be responsible for approximately $2,378 million present value as at April 1, 1999 ($2,938 million as at December 31, 2002) of OPG's low and intermediate level nuclear waste management and decommissioning liabilities; (iii) for the Province to limit OPG's financial exposure in relation to the cost of used fuel management; and (iv) for the Province to provide financial guarantees to the CNSC for OPG's nuclear waste management and decommissioning liabilities in return for an annual guarantee fee equal to 0.5% of the amount

guaranteed. The segregated funds will be administered by a third party and will be kept separate from OPG's other assets. OPG will grant a security interest in both funds to the Province and as a result, the funds will not be available to satisfy the claims of OPG's creditors.

The limits to OPG's financial exposure under the Ontario Nuclear Funds Agreement with respect to the cost of long-term storage and disposal of used fuel are as follows (all amounts are present value as at January 1, 1999): (i) OPG will bear all costs up to $4.6 billion; (ii) OPG and the Province will share, on an equal basis, costs incurred between $4.6 billion and $6.6 billion; (iii) OPG will be responsible for 10% of the costs incurred between $6.6 and $10 billion and the Province will be responsible for the remaining 90%; (iv) the Province will be responsible for any costs above $10 billion. As a result, OPG's liability for these used fuel costs will be capped at $5.94 billion assuming 2.23 million bundles of used fuel waste are produced. OPG will, however, be responsible for all incremental costs relating to the management of used fuel bundles in excess of 2.23 million bundles of fuel waste. The Province is obligated under the agreement to make additional contributions to the used fuel fund if the fund earns less than a specified return over the Ontario consumer price index. The Province is entitled to any surplus in the fund including earnings in excess of the specified return.

OPG's required contributions to the segregated funds have been determined based on internally prepared reference plans, which are prepared with the assistance of external consultants and are based on external practices and benchmarks. Under the reference plan, OPG has estimated the total present value of its future nuclear waste management and decommissioning costs (including its responsibilities in connection with the Bruce stations) based on cost estimates and assumptions as to the remaining useful lives of the nuclear plants and proposed methods of nuclear waste disposal. Cost estimates reflect management's views supplemented by external advice as well as international benchmarks. OPG's estimates as of December 31, 2002 are set out in the following table:

Present Value of Nuclear Waste Management and Decommissioning Cost Estimates

	Present Value December 31, 2002 (millions of dollars)
Incurred liability:	
Decommissioning	$2,702
Nuclear waste management	5,020
Liability as at December 31, 2002	7,722
Less: OEFC commitment	2,938
Less: OPG accumulated funds[1]	1,599
Net unfunded liability	$ 3,185

Notes:

(1) This includes the NFWA trust proceeds of $501 million, the balance to be deposited in segregated funds pursuant to the Ontario Nuclear Funds Agreement.

The current cost estimate for nuclear waste management and decommissioning incorporates several significant assumption changes which lower the overall liability. These changes include a delay in the in-service date for used fuel disposal facilities from 2025 to 2035, the recognition of certain costs associated with dry storage of used nuclear fuel during station operating life, recognition of additional infrastructure costs related to nuclear waste management programs. In aggregate, these cost estimate changes would result in a net reduction to the nuclear waste management and decommissioning liability. In accordance with Canadian generally accepted accounting principles, the change in liability is being amortized over the average remaining service life of the nuclear generating stations based on current financial reference plans.

The *Nuclear Fuel Waste Act* which implements the Federal Government's nuclear fuel waste management strategy came into force in November 2002 and requires owners of nuclear fuel waste to establish a waste

management organization to report regularly to the Federal Government and make recommendations on long-term management of nuclear fuel waste.

The *Nuclear Fuel Waste Act* also requires nuclear fuel waste owners to establish a trust fund to finance implementation of these recommendations. In this regard, OPG established a trust fund and made an initial deposit of $500 million into this trust fund effective November 25, 2002. Further, the *Nuclear Fuel Waste Act* requires that from 2003 onwards, OPG deposit an additional $100 million annually into this trust fund until an approach for long term used fuel management is approved. For purposes of the Ontario Nuclear Funds Agreement, this trust fund will form part of the used fuel segregated fund established under that Agreement and deposits to the trust fund will be made from the used fuel segregated fund. The *Nuclear Fuel Waste Act* requires the waste management organization to submit, within three years of the *Nuclear Fuel Waste Act* coming into force, a study setting out the proposed approaches to managing nuclear fuel waste (including deep geological disposal in the Canadian Shield, storage at nuclear reactor sites and centralized storage either above or below ground) as well as its recommendation as to which of the proposed approaches should be adopted. The study must include for each approach a technical description; a comparison of benefits, risks and costs of that approach compared with those of the other approaches; an implementation plan; and the formula to calculate the annual amount required to finance the approach. The study is to be submitted to the Federal Minister of Natural Resources who is to make a recommendation to the Governor in Council. One of the approaches for the management of nuclear fuel waste shall be selected by the Governor in Council from among those set out in the study. Implementation requirements after selection of an approach are included in the *Nuclear Fuel Waste Act*.

Since April 1, 1999, OPG has been making contributions to a separate account pending the establishment of segregated funds under the Ontario Nuclear Funds Agreement. At the end of 2002, OPG had accumulated a net balance of approximately $1.6 billion on account of the NFWA trust and in this separate account. Once the segregated funds specified in the Ontario Nuclear Funds Agreement are established, funds from this separate account would be transferred to these segregated funds. This is expected to occur in 2003. OPG will make an initial contribution to the decommissioning fund sufficient, when combined with the OEFC contribution and based on current approved estimates, to fully fund its obligations in respect of decommissioning liabilities. In the future, any surplus in the decommissioning fund is shared between OPG and the OEFC on an equal basis; however, OPG is required to direct its share of any surplus into the used fuel fund.

If the decommissioning fund ceases to be fully funded, OPG would be required to make quarterly payments to that fund over the assumed remaining life of nuclear stations based on that fund's assets and earnings (including the OEFC commitment) and the estimated cost of decommissioning and low and intermediate level waste management based on the then current reference plan.

The remaining funds from the separate account will be placed in the used fuel fund consistent with requirements of the Ontario Nuclear Funds Agreement. OPG will thereafter make quarterly payments to the used fuel fund calculated so that if paid over the assumed remaining life of OPG's nuclear stations, these payments, together with fund assets and earnings on accumulated funds, would fund the estimated cost of used fuel management. Based on the Ontario Nuclear Funds Agreement reference plan, the annual contributions to the used fuel fund will be approximately $454 million for the period from 2003 to 2008. OPG's maximum contribution to the used fuel fund would be approximately $700 million annually for the period from 2003 to 2008 if OPG's liability estimate reached the maximum amount possible under the liability thresholds.

OPG's contributions to the segregated funds and any consideration payable in the year to acquire all or part of an interest in such funds are deductible under the proxy tax regime. In addition, investment income earned on these funds is treated by OPG as being exempt from both proxy tax and tax payable under both the *Income Tax Act* (Canada) and the *Corporations Tax Act* (Ontario). If the investment income earned on the segregated funds becomes taxable, OPG will bear the entire additional cost of the tax and its required contributions to the funds would be increased accordingly. See "*Business of OPG – Relationship with the Province and Others – Stranded Debt, Proxy Taxes and Effect of Change in Ownership on Tax Status – Proxy Taxes*", "*Taxation of Provisions for Future Nuclear-Related Costs*" and see "*Business of OPG – Risk Factors – Nuclear Operations*".

Changes to the estimated level of contribution to the funds will depend on any changes to the reference plans and associated cost estimates and tax treatment. OPG's required contributions could increase, for example, if

cost estimates increased, the operating life of the nuclear stations decreased, if the funds became subject to tax or if the NWMO is unable to receive the same sales tax treatment that the Corporation would be entitled to receive if the NWMO had not been established – see "*Business of OPG – Relationship with the Province and Others – Taxation of Provisions for Future Nuclear – Related Costs*". OPG's contributions to the used fuel fund may not, however, decrease until the fund is 60% funded and, after that point, only on a partial basis until the fund is 90% funded. Under the Ontario Nuclear Funds Agreement, payments to the funds are recalculated each time there is a new reference plan and in certain other events. Any new reference plan must be approved by the Province. Reference plans are required to be prepared at least every five years and more frequently if required by the CNSC or if there is a greater than 5% change in the relevant cost estimate.

The CNSC requires obligations for nuclear waste and decommissioning to be subject to financial guarantees. The CNSC published its Regulatory Guide G-206 on "*Financial Guarantees for the Decommissioning of Licensed Activities*" in June 2000. This Regulatory Guide sets out the requirements for the establishment and maintenance of measures to fund the decommissioning of licensed facilities, including the management of all wastes associated with the licensed activity. This Regulatory Guide permits financial guarantees to be in the form of a government guarantee. Under the Ontario Nuclear Funds Agreement the Province would, if required, provide this guarantee in relation to OPG's obligations for an annual fee of 0.5% of the guarantee given. An application was made in November 2002 to the CNSC for the amendment of OPG Class I licences to include conditions for financial guarantees. A hearing with the CNSC is scheduled in April 2003 and the target date for having financial guarantees in place is July 2003. OPG proposes that the guarantee be made up of segregated fund values supplemented by the Provincial guarantee.

In the case of the Bruce A and Bruce B stations leased to Bruce Power, OPG continues to assume long-term responsibility for the used fuel and low and intermediate level radioactive waste generated by Bruce Power, as well as responsibility for eventual decommissioning. Radioactive waste materials will be turned over to OPG during the term of the lease in accordance with nuclear waste agreements between the parties. Under the lease agreement OPG retains the obligation to provide the financial guarantees the CNSC requires regarding the discharge of these liabilities.

Human Resources

As of December 31, 2002, OPG had approximately 11,000 full-time employees and 1,100 contract staff. The majority of OPG's full-time employees are represented by two unions; approximately 6,800 by the Power Workers' Union (the "PWU") and approximately 3,000 by The Society of Energy Professionals (the "Society"). OPG's construction employees are represented primarily by 18 construction trade unions through the Electrical Power System Construction Association (the "EPSCA"). There are approximately 1,200 executive and managerial staff that are not represented by a union.

In January 2002, OPG announced a restructuring plan intended to lead to a company-wide staff reductions of approximately 2,000 employees. As at December 31, 2002 OPG has approved severance packages for approximately 1,400 employees. To the extent possible, a significant portion of the targeted downsizing will be achieved on a voluntary basis. Implementation plans that maximize voluntary reductions were developed in consultation with the PWU and the Society and approximately. In a related initiative, OPG will be relocating nuclear related head office personnel to Durham Region where OPG's two nuclear generating stations are located. Similarly, head office personnel that support OPG's hydroelectric and fossil stations will be relocating to either the Sir Adam Beck facilities near Niagara Falls or to the Nanticoke Generating Station, located in Haldimand County. Based on current estimates, OPG expects the costs of the restructuring plan, including relocation costs, to be approximately $400 million. This restructuring will better align OPG's resources, improve its efficiency and effectiveness and contribute to its future competitive positioning in the electricity market.

OPG believes that its working relationship with its represented employees has steadily improved over the past five years, consistent with an acknowledgement of the necessity of working co-operatively in the new competitive marketplace. In September 2001, the PWU and OPG negotiated a four year agreement to provide labour stability as changes in the electricity industry took place. This was the first time an agreement was reached so far in advance of the expiry of an existing agreement and the first time since 1996 that an agreement was reached

without the assistance of a third party arbitrator/conciliator. Over the past year, the number of grievances outstanding at year end has been reduced from more than 200 to approximately 150.

The Society and OPG have had a longstanding provision in the Society's collective agreement that provides for third party arbitration rather than strike/lockout in the event the parties are unable to reach agreement during collective agreement renewal negotiations. As such, the Society has never engaged in a work stoppage. The last PWU strike was in 1985 and lasted for 10 days. The parties quickly agreed to third party arbitration to resolve their issues. The tenor of negotiations with both unions has varied with the economic climate in Ontario, ranging from challenging and difficult to conciliatory and collaborative. This has resulted in complex collective agreements that have placed constraints on management's flexibility to operate its business.

In 1999, the Society, the PWU and OPG established a "Partnership Agreement" setting out a series of principles that guide the parties in managing day-to-day labour and employment matters. These principles established the framework for the most recent round of collective agreement negotiations with both unions. OPG believes that recent negotiations with both the PWU and the Society reflect a material improvement in its relationships with these unions.

These improved relationships have also enabled OPG, the PWU and the Society to negotiate provisions in the collective agreements that facilitate the implementation of OPG's decontrol commitments. These provisions included the lease of the Bruce A and Bruce B stations in 2001, the decontrol of the Mississagi River facilities in 2002 and the strategic reorganization or outsourcing of support services and non-core businesses, such as information services through the transfer of the operation and support of OPG's information services to New Horizon System Solutions Inc., as described under *"Business of OPG – Information Technology"*, the sale of OPG's interest in Kinectrics Inc. to AEA Technology plc. effective January 1, 2002, as described under *"Business of OPG – Research and Development"* and the divestiture of OPG's nuclear safety analysis division in 2002. In addition to these provisions, OPG's collective agreements contain enhanced provisions for the planning and redeployment of staff and some collective agreements provide a process for the use of purchased services. Grievance resolution procedures in both the PWU and the Society collective agreements provide a streamlined process to handle complaints and help minimize the potential for grievance backlogs. The collective agreements with the Society provide an opportunity to tie compensation to performance and include a commitment to mediation and arbitration with no strikes or lockouts until 2005. The parties have agreed that, upon the completion of OPG's nuclear recovery plan, they will consider whether it is necessary or appropriate to merge the non-nuclear and nuclear collective agreements.

Improved partnership between OPG and the unions is also reflected in the corporate-wide goal-sharing program established in 2000. This is a self-financing incentive plan that gives unionized employees a stake in OPG's financial success through the opportunity to share in earnings in excess of business plan targets. This incentive program, together with incentive opportunities for non-represented employees, means all OPG employees now have a financial stake in OPG's success. OPG believes that these plans have contributed significantly to improved employee understanding of the drivers of business success and will continue to promote and foster innovation, flexibility and a continuous raising of the performance bar.

OPG also negotiates directly with three building trade unions in the construction sector, the Machinists and the Canadian Union of Skilled Workers and the Brick and Allied Craft Union. Collective agreement terms for each of these unions are in place until April 30, 2004.

During the 2001 negotiations with the PWU, there were major changes made to the wage structures and work assignment portions of the collective agreement. The concept of skill broadening was introduced. Skill broadening allows employees to work outside of their traditional roles by performing a wider range of duties. This is expected to improve productivity and employee job satisfaction. Employees were also placed into three pay bands and the number of job documents was reduced from over 1,000 to about 100. In addition, a large number of premium payments were reduced. In the PWU collective agreement for the non-nuclear business unit, management's flexibility to contract out work was enhanced and employees covered by that agreement received an employment guarantee for the life of the agreement which expires on March 31, 2006. This collective agreement covers approximately 2,600 employees.

OPG also provides programs that help prepare OPG for competition in the Ontario market, including programs that attract and retain skilled personnel, enhance the business and financial orientation of employees, ensure that OPG has appropriate succession planning and leadership development and support increased focus on safety and wellness. See "*Business of OPG – Health and Safety– Occupational Health and Safety*".

Health and Safety

Occupational Health and Safety

OPG is committed to the safe operation of all its facilities and to workplace health and safety excellence. This commitment stems in part from the fact that OPG's historic health and safety record was considered by management to be insufficient. Notwithstanding management's commitment in this regard, OPG did have an employee fatality in 2002, an accident near OPG's Barrett Chute station which resulted in the death of two members of the public and a number of near-miss incidents that could have lead to serious injuries or fatalities. OPG senior management is therefore taking deliberate steps to further enhance the focus on safety.

Corporate performance measures for safety address accident severity and injury rates and are monitored quarterly and annually. Local safety measures are also required and safety targets have been incorporated into the goal-sharing compensation program applicable to OPG's unionized employees. Management and employee compensation is tied, in part, to success in achieving this goal. As a result of the employee fatality at the Nanticoke facility and a number of long-term work related absences, OPG did not meet its "accident severity rate" safety target in 2002.

In order to enhance matters regarding public and contractor safety, the OPG health and safety policy was revised to provide additional requirements in these areas. A number of improvement initiatives aimed at reducing high risk issues (including in-depth public safety, coal handling and contractor safety assessments) were launched. Hazards continued to be identified throughout the organization and operational controls implemented to mitigate these risks in accordance with the *Occupational Health and Safety Act* (Ontario) and industry best practices. Going forward, OPG will be intensifying its efforts in this regard.

OPG's conventional safety management system is being enhanced to conform with the British Standards Institute's Occupational Heath and Safety Assessment Series 18001 ("OHSAS 18001"), which is consistent with the ISO 14001 standard adopted for OPG's environmental management system. Standards and procedures are being updated throughout OPG in accordance with this model. A number of hydroelectric and fossil facilities have already received recommendations for registration according to the OHSAS 18001 specification document.

Safety continues to be of paramount importance at OPG and is profiled prominently through leadership actions and communications.

Radiation Safety

OPG manages a radiation protection program designed to minimize detrimental health effects to employees and members of the public. OPG follows developments in the field of radiation protection as documented by the International Commission on Radiological Protection (the "ICRP"), the United Nations Scientific Committee on the Effects of Atomic Radiation and the U.S. National Council on Radiation Protection and Measurements. The ICRP is widely recognized as the main source of expert advice regarding protection from the harmful effects of ionizing radiation. This agency periodically issues recommendations concerning principles of radiation protection. The recommendations of the ICRP are usually adopted without significant change by most countries and are incorporated into their laws. In Canada, the CNSC is the Federal agency that regulates radiation protection. The Canadian Radiation Protection Regulations are based on the recommendations of the ICRP, and OPG nuclear facilities conform to these regulations.

Radiation exposures to plant personnel and the public are limited by station design and by adherence to approved operating procedures. Over the years, OPG has been a leader in the application of the principles of "ALARA" (keeping radiation doses As Low As Reasonably Achievable). The CANDU station design has steadily improved with each new plant. Notable achievements were the reduction of radiological source terms (such as Cobalt-60), the implementation of a tritium displacement and removal strategy and the integration of enhanced

shielding in the design of plants. OPG's administrative limits for occupational exposure are set below regulatory limits to ensure that regulatory limits are not exceeded. Operating targets for radiological emissions are even more restrictive and are typically small fractions of the regulatory limits.

Each nuclear site has a radiation protection department which continually reviews and assesses the radiation control program. The department's staff complement includes health physicists who have been certified by the CNSC. The certified health physicists are charged with monitoring compliance with radiation protection policies and regulations.

All persons who enter the operating area of a nuclear facility are assigned a radiation protection qualification that determines access and working rights. Workers that perform radioactive work are extensively trained to look after their own radiation protection. Radioactive work is done in accordance with approved work plans or procedures.

A dosimetry program licensed by the CNSC monitors radiation exposures of workers. Results of the dosimetry program are routinely reported to the National Dose Registry of Health Canada, as required by the CNSC. Potential radiation exposure of the public is monitored through a comprehensive environmental program that has been designed to monitor site specific exposure pathways to a member of the public, such as drinking water and foodstuffs. The results of this monitoring program are reported annually to the CNSC.

As a condition of receiving operating licences for its nuclear facilities, OPG has developed comprehensive emergency plans which detail its planned response to reactor accidents as well as accidents involving the transportation of radioactive materials. These plans dictate how OPG will work with municipal, regional, provincial and Federal agencies to safeguard station personnel and members of the public in the unlikely event of a radiation emergency at one of OPG's facilities. Plant staff regularly participate in emergency exercises to maintain their skills and to continuously improve response capability for such events.

Public Safety

A commitment to public safety is an important part of the operation of all OPG generating stations. However, on June 23, 2002, a tragic accident did occur at the Barrett Chute hydroelectric facility involving two fatalities to members of the public. A review of OPG's policies with respect to public safety followed this accident. This review resulted in an initiative to improve site security and public safety at all generating stations. An assessment of the public safety control measures in place at each of hydroelectric generating stations and control dams was conducted. The scope of the assessment was subsequently increased to include the cooling water intakes and outfalls at OPG's nuclear and fossil generating stations. Expenditures of approximately $10 million will be made to implement the recommended improved control measures. As well, a number of additional initiatives are underway to increase public awareness and education with respect to public safety around OPG's facilities.

Intellectual Property

In connection with the reorganization of Ontario Hydro, Ontario Hydro's patents and certain other transferable intellectual property assets, including trade-marks, copyrights and industrial design and technical information (including know-how and technical knowledge) were transferred to certain successor corporations. Certain of the intellectual property assets transferred to OPG have, in turn, been licensed by the Corporation to Hydro One and the Electrical Safety Authority for use solely in connection with such parties' business; OPG has been granted corresponding licences as part of the reorganization. Licences of intellectual property assets among the Corporation, Hydro One and the Electrical Safety Authority are generally non-exclusive, royalty free and perpetual and cannot be terminated without the written consent of the other party.

Research and Development

Historically, most of OPG's non-nuclear research was conducted by its Ontario Power Technologies ("OPT") division. In August 2000, OPG transferred certain assets (including many patents) relating to its OPT division to Kinectrics Inc., a new independent science and engineering services company, in return for a 90% interest in Kinectrics Inc. The remaining 10% interest was owned by C-SAT Technologies Inc. ("C-SAT"), a

consortium comprised of AEA Technology, plc and the partnership of Canatom NPM Inc. and Scientech Canada Inc. Effective January 1, 2002, OPG sold its 90% interest in Kinectrics Inc. to a Canadian subsidiary of AEA Technology plc. AEA Technology plc., formerly part of the United Kingdom Atomic Energy Authority, operates in 31 countries. OPG expects to continue as a significant customer of Kinectrics Inc. and has committed to make certain levels of purchases from Kinectrics in each of 2002, 2003 and 2004.

The majority of OPG's R&D effort is operationally based and primarily focused on short-term, lower-risk programs aimed to improve productivity, reduce costs, meet changing environmental and regulatory considerations and make other types of incremental improvements that will improve operational performance and operating results. OPG has adopted this mission oriented approach decentralizing these operational R&D initiatives to operating business units.

Most of OPG's nuclear research and development is conducted at Atomic Energy of Canada Limited and at private sector facilities by the private sector facilities and focuses on improving plant performance, plant life cycle management and regulatory excellence.

Longer term strategic programs are managed at the corporate level. Corporate programs focus on the advancement and commercialization of next generation technologies in support of OPG's business activities and include technologies such as fuel cells, distributed generation and energy storage.

Whether pursued independently, through corporate initiatives, its venture capital subsidiary, OPG Ventures Inc., or using other investment platforms, OPG focuses on building expertise in understanding the advancement of new and sustaining energy technologies to provide opportunities to invest in and exploit future energy technologies such as fuel cells and renewable energy options. OPG management believes that this strategy will assist OPG in preparing for and capitalize on major industry changes over time.

Venture Capital

OPG Ventures Inc., a wholly owned subsidiary of OPG, was incorporated in March 2001 for the purpose of investing in emerging technologies related to the energy industry. OPG Ventures Inc.'s strategy is to optimize financial returns by making equity investments in private companies which have or are developing enabling or break-through technologies and who are at the advanced start-up or later stage of growth. OPG Ventures Inc. plans to invest up to $100 million over its initial term of operation and had invested $31 million as of December 31, 2002 and had $18 million in outstanding commitments, up to half of which is expected to be invested in 2003. Included in the initial investments are companies developing technologies such as fibre optic high voltage power measurement, energy generation from waste using plasma gasification and enterprise energy management solutions.

Information Technology

OPG's competitiveness depends in part on its ability to effectively implement best practices and leading edge information technology systems and operations. OPG has implemented and is supporting the information technology systems necessary to manage the changes and new opportunities in Ontario's deregulated electricity market and the emerging North American energy markets. These systems automate and integrate business processes to facilitate OPG's participation in the IMO-administered market and other interconnected markets and include systems for production planning, spot market bidding, generation dispatch, settlement of spot market and bilateral transactions, billing, customer information and services, trading and risk management.

OPG has implemented a number of strategies to enhance the management of the information systems support for its business units. These include: enhanced information technology expertise through training and hiring, continued reductions in the cost of information technology services and the successful delivery of large scale projects, such as the fossil and hydroelectric systems' restructuring and rebuilding of the data centre and communications networks. In November 2000, OPG entered into a joint venture agreement with a wholly owned subsidiary of Cap Gemini Canada Inc., to transfer the operation and support of OPG's information services to New Horizon System Solutions Inc. ("New Horizon"). Approximately 600 employees from OPG's Information Services Group transferred to New Horizon on February 1, 2001. Effective March 28, 2002, OPG sold its remaining 49% interest in New Horizon to Business Transformation Services Inc. New Horizon will continue to perform infrastructure management, application development, application support and maintenance, network management,

data centre operations and help desk support services for OPG on a contract basis and will also deliver information technology services throughout the energy industry. The New Horizon divestiture has allowed OPG to reduce the costs associated with managing and maintaining information systems internally, while allowing management to focus on strategic and core business priorities. The divestiture also assists OPG in scaling its information technology resources appropriately as it implements measures to meet its decontrol commitments.

In January 2001, OPG entered into the EBT Express joint venture with Toronto Hydro Corporation. Effective March 7, 2002, EBT Express, Screaming Power Inc. and Screaming Solutions Ventures Inc. (which, among other things, is in the business of developing, marketing and licensing secure messaging software products and systems for use in the electricity industry) combined their operations into a new company, "The SPi Group". The SPi Group's electronic clearinghouse technology is now in production and provides e-commerce services for retail transaction management to market participants in the energy sector including utilities, retailers and other energy services providers.

Insurance

The principal types of discretionary insurance carried by OPG include commercial general liability, all risks property, boiler and machinery breakdown, including statutory boiler and pressure vessel inspections and business interruption. In addition to covering OPG's non-nuclear facilities, this insurance applies to the conventional operations at OPG's nuclear generating stations. OPG also maintains property insurance for damage to the nuclear portions of its generating stations which complements the conventional property insurance program. As a result of significant changes in the insurance marketplace, due in part to the September 11, 2001 terrorist acts, the available coverage and limits may be less than the amount of insurance obtained in the past and the recovery for losses due to terrorist acts may be limited. OPG is self-insured to the extent that any losses may exceed the amount of insurance maintained.

OPG purchases insurance coverage as required by statute, namely owned and leased automobile and nuclear liability. OPG believes that the coverages, amounts and terms of its insurance agreements are consistent with prudent Canadian industry practice.

As required by the *Nuclear Liability Act* (Canada) (the "NLA"), OPG maintains $75 million per incident of nuclear liability insurance for each of its nuclear generating stations (Pickering A and B are considered to be one station), for which there is no deductible amount. The NLA is currently under review, which will likely result in a requirement for increased insurance coverage. OPG has been advised by its nuclear liability insurers that it would likely be able to obtain nuclear liability insurance in respect of any increased coverage requirements. OPG expects that the incremental cost of such coverage would not have a material adverse effect on its business, results of operations, financial condition or prospects. See *"Business of OPG – Regulation – Nuclear Regulation"*.

Relationship with the Province and Others

Provincial Authority

As a corporation governed by the *Business Corporations Act* (Ontario), the Corporation's management is supervised by its Board of Directors which is obligated to act in the best interests of the Corporation. The Province owns all of the Corporation's issued and outstanding common shares and thereby has the power to determine the composition of the Corporation's Board of Directors.

The OEB, the principal regulator of Ontario's electricity industry, is an independent quasi-judicial tribunal created by the *Ontario Energy Board Act, 1998* (the "OEB Act, 1998"), reporting to the Ontario legislature through the Minister of Energy. The OEB consists of no fewer than five members appointed by the Province and various staff groups. The OEB is obligated to implement the Province's directives concerning (i) conservation; and (ii) together with the IMO, those intended to address existing or potential abuses of market power. See *"Business of OPG – Regulation – Ontario's Electricity Industry – Legislation"*.

The IMO is a separate entity operating independently through its board of directors. The Province exercises statutory powers in relation to the IMO. The IMO's board of directors is responsible for managing or supervising the management of the IMO's business and affairs and board members are subject to fiduciary

obligations in the performance of their duties in accordance with the *Electricity Act, 1998*. Directors of the IMO are appointed by the Province for terms not exceeding three years and may be reappointed, but may only be removed by the Province or the board of directors of the IMO for cause. The Chief Executive Officer of the IMO is selected by the board and also serves as an IMO director. See *"Business of OPG – Regulation – Ontario's Electricity Industry – The IMO"*.

Transfer Orders and Indemnities

On April 1, 1999, pursuant to transfer orders made by Order in Council pursuant to the *Electricity Act 1998*, OPG purchased and assumed all of the interest of Ontario Hydro in all officers, employees, assets, liabilities, rights and obligations of Ontario Hydro directly or indirectly used in or relating in any manner to the activities carried on by Ontario Hydro as a generator as at April 1, 1999. OPG entered into an indemnity agreement with the OEFC in respect of assets, liabilities, rights and obligations pertaining to OPG's business. Under this agreement, the OEFC has indemnified OPG in respect of: the failure of the transfer orders to transfer any asset, right or thing, or any interest related to OPG's business; any adverse claims or interests, excluding certain claims and rights of the Crown, or any deficiency or lack of title in respect of any asset, right or thing or any interest, which was intended to be transferred. The indemnity specifically excludes various claims, including: (i) any matter in respect of which OPG has agreed or is required to indemnify the OEFC pursuant to or in connection with any transfer order; and (ii) any claims related to First Nations title or rights, or the absence of permits, rights-of-way, easements or similar rights in respect of lands held for First Nations bands or bodies under the *Indian Act* (Canada).

The indemnity does not cover the first $10,000 in value of each claim and only applies to the amount by which the total of all claims exceeds $20 million. OPG is obliged to pay the OEFC a fee for the indemnity of $5 million per year, until such time as OPG and the OEFC agree that the indemnity should be terminated. The Province has guaranteed the obligations of the OEFC under the indemnity agreement.

Relationship with the Province

Shareholder's Agreement and Dividend Policy

The Corporation and the Province have entered into a shareholder's agreement relating to certain aspects of the governance of OPG. The shareholder's agreement addresses such issues as the provision, from OPG to the Province, of the information necessary to allow the Province to periodically inform Ontario's legislature regarding matters such as the ongoing performance of OPG, progress reports concerning compliance with market power mitigation, information in respect of matters requiring shareholder approval and appropriate financial reports. In addition, the shareholder's agreement addresses OPG's governance relationship with the Province with respect to certain actions, including any proposal to issue or transfer shares in the Corporation or any of its subsidiaries, the preparation of long-term business plans, matters concerning dividend policy and the entering into of any major transaction by the Corporation or any of its subsidiaries which would potentially have a material effect on the financial interest of the Province or OPG's ability to make payments in lieu of taxes. The shareholder's agreement also precludes the release by the Province of non-public, commercially sensitive information regarding OPG to Hydro One or others.

The declaration and payment of dividends are at the sole discretion of the Corporation's Board of Directors and will be dependent upon the Corporation's results of operations, financial condition, cash requirements, securities legislation and other factors considered relevant by the Corporation's Board of Directors. The Corporation's policy is to declare and pay regular dividends on its common shares held by the Province equal to approximately 35% of its net income from time to time. In addition, the Corporation may from time to time declare special dividends on account of any portion of the proceeds of any decontrol transactions that are received by the Corporation and that the Corporation determines should be distributed to its shareholder. The Corporation has no plans to change its dividend policy.

In 2002, the Corporation made dividend payments to the Province in the aggregate amount of $133.55 million. These payments are comprised of (i) a regular dividend payment in the aggregate amount $10.15 million representing the regular dividends remaining on account of 2001 net income; and (ii) a special dividend payment of $123.40 million, representing the final dividend based on net proceeds received by OPG from Bruce Power with respect to the decontrol of the Bruce facility. No dividend payments were made during 2002 on account of 2002

financial results, however, a dividend payment of $16.55 million was made on March 31, 2003, representing 35% of the Corporation's net income for 2002.

Ontario Nuclear Funds Agreement

OPG and the Province have executed the Ontario Nuclear Funds Agreement, under which the Province has agreed to limit OPG's financial exposure in relation to certain used fuel management costs. See *"Business of OPG – Generation Operations – Nuclear Operations – Nuclear Waste Management and Decommissioning – Provisions for Future Nuclear-Related Costs"*.

Indemnities

The Province has provided an indemnity in favour of the Corporation and has guaranteed certain obligations of the OEFC to OPG under the indemnity agreements between OPG and the OEFC. See *"Business of OPG – Relationship with the Province and Others – Transfer Orders and Indemnities"*.

Stranded Debt, Proxy Taxes and Effect of Change in Ownership on Tax Status

Stranded Debt

One of the OEFC's purposes under the *Electricity Act, 1998* is to manage its outstanding liabilities, including "stranded debt". The *Electricity Act, 1998* defines stranded debt as the amount of the debt and other liabilities of the OEFC that, in the opinion of the Minister of Finance, cannot reasonably be serviced and retired in a competitive electricity market. At April 1, 1999, the Province estimated the stranded debt to be $20,900 million, representing the difference between OEFC's existing debt and liabilities of approximately $38,100 million and the aggregate enterprise value of OPG, Hydro One and the IMO of $17,200 million. Although OPG has no obligations in connection with the stranded debt, the *Electricity Act, 1998* does provide for stranded debt to be paid over time by payments to the OEFC by participants in the electricity sector, including OPG, Hydro One and the local distribution companies. These payments include proxy taxes, debt retirement charges levied on electricity consumers, and other amounts that may be payable by local distribution companies or municipal corporations on the transfer of their electricity business.

Proxy Taxes

The Corporation and its Canadian subsidiaries are exempt from tax under the *Income Tax Act* (Canada) and *Corporations Tax Act* (Ontario) because the Province is the sole shareholder of the Corporation, the Corporation owns not less than 90% of the shares or capital of its subsidiaries and no non-government entity has an option or other right to acquire more than 10% of such shares. The *Electricity Act, 1998*, however, requires each corporation to pay to the OEFC for each taxation year, an amount referred to as "proxy tax" as long as it continues to be exempt from tax under the *Income Tax Act* (Canada) and *Corporations Tax Act* (Ontario). Proxy taxes in general, equal the amount of tax payable under the rules in the *Income Tax Act* (Canada) and the *Corporations Tax Act* (Ontario), as modified by the regulations to the *Electricity Act, 1998*, if the corporation were not exempt. Under the regulations to the *Electricity Act, 1998*, contributions to a nuclear decommissioning fund or nuclear used fuel fund are deductible in computing income subject to proxy tax. In addition, any related investment income earned on these funds is treated by the Corporation as being exempt from proxy tax and tax under the *Income Tax Act* (Canada). See *"Business of OPG – Relationship with the Province and Others – Stranded Debt, Proxy Taxes and Effect of Change in Ownership on Tax Status"*, and *"Taxation of Provisions for Future Nuclear-Related Costs"*, and *"Business of OPG – Generation Operations – Nuclear Operations – Nuclear Waste Management and Decommissioning – Provisions for Future Nuclear-Related Costs"*.

The *Electricity Act, 1998* also provides that the Corporation and certain of its Canadian subsidiaries are required to make payments in lieu of property tax to the OEFC on their non-hydroelectric generating station buildings and structures each year. These payments in general, equal the difference between property taxes otherwise payable if these assets were privately-owned, and the amount as determined under the *Electricity Act, 1998*. This difference is paid to the OEFC to be applied to its stranded debt. One of the purposes of the proxy tax and the payments in lieu of property tax is to create a level playing field, from a tax perspective, between OPG and other generators seeking to sell electricity in the Ontario market. The Corporation's hydroelectric generation

subsidiaries do not make payments in lieu of property taxes because they are subject to the gross revenue charge regime. See *"Business of OPG – Relationship with the Province and Others – Special Charges on Hydroelectric Generating Stations"*.

Effect of Change in Ownership on Tax Status

The current tax-exempt status of the Corporation and its Canadian subsidiaries under the *Income Tax Act* (Canada) and the *Corporations Tax Act* (Ontario) might be lost under a number of circumstances, including if the Province of Ontario ceases to own 90% or more of the shares or capital of the Corporation, or if a non-government entity has rights immediately or in the future, either absolutely or contingently, to acquire more than 10% of the shares of the Corporation. If the Corporation becomes taxable under these tax acts, it will no longer be subject to proxy taxes. The impact in general of losing this tax-exempt status is that the Corporation is deemed to have a new taxation year and to have disposed of and reacquired its assets at fair market value, for purposes of computing its income in the future as a taxable corporation. Also, for certain provisions, the Corporation is deemed to be a new corporation and as a result, tax credits, and tax losses not previously utilized by the Corporation will not be available to it after the change in tax status. Essentially, the Corporation would be taxed as though it had a "fresh start" at the time of its change in tax status.

The amount of taxes the Corporation would pay as a taxable corporation may differ from proxy taxes mainly because of the difference in the tax value of assets after the change in tax status from that which applied earlier. If the fair market value of the Corporation's depreciable assets exceeds their undepreciated capital cost under the proxy tax regime at the time of change in tax status, its corporate tax liability will likely be reduced, as it will be eligible for higher capital cost allowance claims in the future. The opposite result would arise if the fair market value is less than their undepreciated capital cost. In addition, there can be no assurance that OPG's contributions in respect of the nuclear decommissioning or nuclear used fuel funds would continue to be tax deductible in determining the tax liability of the Corporation nor that related investment income would continue to accumulate on a tax-free basis. See *"Business of OPG – Generation Operations – Nuclear Operations – Nuclear Waste Management and Decommissioning – Provisions for Future Nuclear-Related Costs"*, and *"Business of OPG – Relationship with the Province and Others – Taxation of Provisions for Future Nuclear-Related Costs"*. However, the Corporation has been engaged in discussions with the relevant taxation authorities to review various alternative structures or arrangements whereby such contributions would continue to be tax deductible with related investment income earned continuing to be tax-exempt.

If the Corporation becomes taxable under the *Income Tax Act* (Canada) and the *Corporations Tax Act* (Ontario), then it will be required under the *Electricity Act, 1998* for proxy tax purposes, to pay a proxy tax (referred to as the "Exit Tax") to the OEFC, on any income deemed to have been realized upon the deemed disposition of its assets at their then fair market value. Where a corporation, however, loses its tax exempt status, as a result of an initial public offering of its shares it may, with the consent of the Minister of Finance, determine the amount of Exit Tax prior to losing its tax-exempt status (i.e. prior to the time the shares are issued to the public) using a reasonable estimate of the future fair market value of the assets at the time the corporation ceases to be tax-exempt. Once the amount of the Exit Tax has been agreed to by the Minister of Finance, it cannot be varied or altered unless the Corporation made a misrepresentation in estimating the Exit Tax amount.

Special Charges on Hydroelectric Generating Stations

Since 2001, the Corporation has been paying gross revenue charges based on the gross revenue derived from the annual generation of electricity from its hydroelectric generating stations. These charges are calculated on a station-by-station basis and consist of a graduated portion, paid to the OEFC to fund the stranded debt; and an additional 9.5% portion, paid to Province because it replaces the water rental payments under the old system. *See "Business of OPG – Generation Operations – Hydroelectric Operations – Water Rental Payments"*. The graduated portion consists of four tiers of payments as follows- the gross revenue arising from the first 50 gigawatt hours of annual generation from the generating station is assessed at 2.5%, the next 350 gigawatt hours is assessed at 4.5%; the next 300 gigawatt hours is assessed at 6%, and the generation above 700 gigawatt hours is assessed at 26.5%. The additional gross revenue charge of 9.5% is levied on the gross revenue of the Corporation's hydroelectric generating stations that are located on provincial Crown lands.

Pursuant to the regulations of the *Electricity Act, 1998*, the gross revenue of a station for the period January 1, 2001 to December 31, 2003, is determined by multiplying the station's annual generation for the year by a price of $40 per MWh. The determination of gross revenue post-2003 will be set by future regulations which have not yet been released. The Corporation's estimated gross revenue charges for 2002 is $328 million. Property tax on land and buildings not used in connection with the hydroelectric generating station will continue to apply and be paid by the Corporation directly to the municipality and is not expected to be significant.

Taxation of Provisions for Future Nuclear-Related Costs

The Corporation treats any related investment income earned by the nuclear decommissioning and nuclear used fuel funds as being exempt from proxy tax – see "*Business of OPG – Stranded Debt, Proxy Taxes and Effect of Change in Ownership or Tax Status Proxy Taxes*". Such income is also tax-exempt under the *Income Tax Act* (Canada) and *Corporations Tax Act* (Ontario) because the Corporation is tax-exempt. However, because the Corporation established a trust pursuant to the *Nuclear Fuel Waste Act* to fund its long-term management of used fuel, this trust is taxable as a separate entity under the *Income Tax Act* (Canada). As a taxable entity, the trust would normally be required to pay tax on any related investment income earned because such funds remain in the trust. However, the Federal Government has indicated to the provinces of Ontario, Quebec and New Brunswick, that it will take appropriate measures to ensure that such income is exempt from taxation under the *Income Tax Act* (Canada) if the beneficiaries of the trust are the Province, the Federal Government, or a Crown-owned nuclear energy corporation that is exempt from taxation under the *Income Tax Act* (Canada). Since the trust fund meets these conditions, its income would be tax-exempt under the *Income Tax Act* (Canada).

The Corporation is currently entitled to recover its goods and services tax ("GST") under the *Excise Tax Act,* (Canada) paid on its purchases and expenses related to its nuclear waste operations. Under the *Nuclear Fuel Waste Act*, the management of long-term used fuel disposal will be performed by the Nuclear Waste Management Organization ("NWMO") that was recently created under the *Nuclear Fuel Waste Act*. There is a risk that the NWMO may not be able to recover its GST because it may not be considered to be carrying on a commercial activity. If this occurs, the Corporation estimates that its costs for the funding of long-term used fuel disposal would increase by approximately $262 million for the disallowed GST calculated on a present value basis as of January, 2002. The Corporation is in discussions with the federal tax authorities with a view to obtaining the appropriate remedy.

Regulation

Ontario's Electricity Industry

Legislation

The *Electricity Act, 1998* implements the fundamental principles of the restructuring of Ontario's electricity industry. These include the separation of the competitive parts of the industry (generation and retail) from the natural monopoly parts of the industry (transmission and distribution), the establishment of an independent electricity market operator and the implementation of non-discriminatory access to transmission and distribution systems.

The OEB Act, 1998 expands the jurisdiction and mandate of the OEB in the regulation of the electricity and natural gas markets. In its role as regulator of the Ontario electricity market, the OEB has broad powers relating to licensing, rate regulation and market supervision. The OEB is obligated to implement the Province's directives concerning conservation matters as well as those in tended to address existing or potential abuses of market power by energy sector participants or matters that relate to the Market Power Mitigation Agreement directive. Upon the petition of any party or interested person, the Province may require the OEB to review all or any part of an order that the OEB has issued.

The purposes of the *Electricity Act, 1998* and the objectives of the OEB pursuant to the OEB Act, 1998 are to: facilitate competition in the generation and sale of electricity and to facilitate a smooth transition to competition; provide generators, retailers and consumers with non-discriminatory access to transmission and distribution systems in Ontario; protect the interests of consumers with respect to prices and reliability and quality of electricity service; promote economic efficiency in the generation, transmission and distribution of electricity; facilitate the

maintenance of a financially viable electricity industry; and promote energy conservation, energy efficiency, load management and the use of cleaner energy sources, including alternative and renewable energy sources, in a manner consistent with the policies of the Province. An additional purpose of the *Electricity Act, 1998* is to ensure that Ontario Hydro's debt is repaid in a prudent manner and that the burden of such debt is fairly distributed.

The key regulatory instruments authorized by the *Electricity Act, 1998* and the OEB Act, 1998 that apply to OPG and its business are: the transfer orders issued by the Lieutenant-Governor in Council; the Market Rules made by the IMO; and OPG's generator, wholesale and retail licences issued by the OEB. Elements of the restructuring of Ontario's electricity industry are in place, including the regulations and Market Rules that govern the competitive wholesale and retail electricity markets. These regulations and Market Rules include technical provisions dealing with participation in the markets, the delivery of energy through the IMO-controlled grid and the provision of certain ancillary services and the IMO's financial markets arrangements.

Since Market Opening, a number of amendments have been made to both the *Electricity Act, 1998* and the OEB Act, 1998 through the following legislation: Bill 58, the *Reliable Energy and Consumer Protection Act, 2002* and Bill 210, the *Electricity Pricing, Conservation and Supply Act, 2002*, plus related regulations. Bill 58 focused on the conduct of retailers selling to consumers who use less than 150,000 kWh of electricity annually. This has little direct impact on OPG. Bill 58 also increased the investigative power of the IMO Market Surveillance Panel ("MSP"). The changes implemented by the *Electricity Pricing, Conservation and Supply Act, 2002* are discussed in more detail under the following sections *"Background – Ontario's Electricity Market – Bill 210, Related Regulations and Government Announcements"*, *"Business of OPG – Risk Factors – Restructuring of Ontario's Electricity Industry"* and *"Government Regulation"*. In summary, this statute and related regulations have enacted a number of amendments to the regulation of the Ontario electricity market. One of the main changes, fixing the price at which low-volume and other designated consumers purchase electricity, is intended to be in effect until repealed by proclamation of the Lieutenant Governor, but the repeal cannot occur before May 1, 2006.

Market Opening

The *Electricity Act, 1998* mandates non-discriminatory access to transmission and distribution facilities by providing that every transmitter or distributor must provide generators, retailers and consumers with non-discriminatory access to its transmission or distribution systems in Ontario in accordance with its licence. See *"Business of OPG – Regulation – Ontario's Electricity Industry – Market Power Mitigation – Rebate Mechanism and Transitional Price"*.

For at least the first 18 months after May 1, 2002, there will be a uniform market-clearing price within Ontario calculated on a congestion-free basis. Settlements for generators and consumers will be based on metered energy multiplied by the uniform market price. If transmission constraints or line losses require less expensive generation to be removed from production and more expensive generation to produce more electricity, the constrained generators will be compensated by an additional payment which will be charged to consumers. During this initial 18 month period, the IMO is collecting and publishing locational pricing data to determine the extent of congestion in the Ontario market and will recommend whether to move to some form of congestion pricing after this initial period. Depending on the extent of congestion, this change could result in locational pricing, in which individual market clearing prices would be established for various locations in Ontario. Interconnections with other jurisdictions are treated as separate zones from the rest of Ontario and separate zone prices apply when an interconnection is constrained.

In anticipation of Market Opening, a regulation was enacted by the Province known as Transition Generation Corporation Designated Rate Options. Under this regulation OPG is required to provide transitional price relief following Market Opening to certain customers, effectively providing them with an extension of various pricing options that they had received prior to Market Opening. These contracts have the effect of hedging the price at which OPG sells electricity. The maximum length of the program is four years, with the possibility that it will expire after only two years if certain decontrol targets are met. In the first quarter of 2002, a provision of $210 million was recorded by OPG based on the estimated future losses on these contracts. Since Market Opening, $66 million has been charged against this provision.

The IMO

The IMO functions both as independent system operator, ensuring overall system reliability and stability through control of physical dispatch, and as independent market operator, the clearing house for the settlement of spot transactions by suppliers and purchasers of electricity participating in the IMO wholesale market.

Under the *Electricity Act, 1998*, the IMO is authorized to make and enforce the Market Rules which are necessary to perform its function and administer the IMO-controlled market. Bill 210 gave the Minister of Energy the power to review rule amendments before they are implemented. Each market participant is obliged to follow the Market Rules in accordance with its participation agreement with the IMO and its OEB licence.

Unless exempted by regulation or the Market Rules, all persons require authorization from the IMO to participate in the IMO-administered markets or cause or permit electricity to be conveyed into, through or out of the IMO-controlled grid. In addition, the IMO and all generators, transmitters, distributors, wholesale sellers, wholesale buyers and retailers have to obtain a licence from the OEB in order to participate in the Ontario electricity market.

The IMO acts as a clearing house for the settlement of spot market transactions as well as designated physical bilateral contracts between IMO market participants and sends invoices to market participants. Credit risk in the settlement process is managed by IMO rules requiring all authorized market participants to satisfy requirements for creditworthiness, with all participants sharing the risk of loss on a market participant's payment default on a *pro rata* basis.

The IMO-administered physical electricity markets includes real-time markets. The spot markets for energy and operating reserve are both part of the real-time markets that are administered by the IMO. The energy market deals with offers to sell and bids to purchase electricity. Operating reserve is generating capacity that can be called upon or demand that can be reduced on short notice by the IMO, for example, to replace scheduled electricity supply that is unavailable as a result of contingencies such as unexpected outages of generating facilities, or deal with unanticipated increases in demand. The IMO establishes separate prices for the energy market and the operating reserve markets. The IMO jointly optimizes these two markets to produce dispatch instructions and prices intended to result in the most cost-effective overall solution for the market. The description below of how the IMO establishes the market clearing prices of electricity and operating reserve does not include adjustments that result from the interaction of the energy and the operating reserve markets. Furthermore, the following description is based upon the assumption that there are no constraints in the transmission system. If there are constraints in the transmission system, further adjustments are made to dispatch instructions and the compensation paid to generators.

In the energy market, offers to sell specified quantities of electricity at specified prices for each hour of a given day (the "dispatch day") are made by generators in Ontario and elsewhere. Intermittent and small generation facilities may be designated as "non-dispatchable", in which event they receive the market clearing price for all electricity generated by the facility, without the need to submit an offer to sell to the IMO. All other generators are "dispatchable" and are only dispatched if their offer is accepted.

Consumers may similarly submit bids that specify the maximum price that the consumer is willing to pay for electricity. Such consumers are considered to be "dispatchable". If a consumer submits such a bid, when the price of electricity exceeds the price in its bid, the consumer must reduce its electricity usage based on dispatch instructions from the IMO. If such consumer does not follow the IMO dispatch instructions, it generally will be in breach of the Market Rules. All other consumers are "non-dispatchable". Non-dispatchable consumers do not submit bids and pay the hourly market clearing price for all electricity consumed by them.

Offers from generators and bids from consumers are provided to the IMO in advance of the dispatch day and may be changed within certain time limits. For each five-minute interval, the market clearing price is set by the price of the next available bid or offer that has been submitted to the IMO to meet the next MW of demand. This price can, therefore, be set by an offer submitted by a dispatchable generator or by a bid submitted by a dispatchable consumer. The IMO also establishes an hourly market clearing price, which is the arithmetic average of the five-minute interval market clearing prices during that hour. All dispatchable generators and dispatchable consumers whose offers or bids are accepted by the IMO receive or pay the five-minute interval market clearing price for electricity generated or consumed, based upon metered quantities. All non-dispatchable generators and non-

dispatchable consumers receive or pay the hourly market clearing price for electricity generated or consumed by them based on metered quantities.

The operating reserve markets establish market clearing prices that are paid to parties whose offers to provide operating reserve are accepted by the IMO. As mentioned above, these prices are affected by the interaction between the energy market and the operating reserve markets.

The IMO maintains the reliability of the transmission grid through ancillary services (operating reserve, reactive support/voltage control service, black start capability and automatic generation control) and must-run contracts for local reliability. Ancillary services other than operating reserve are purchased by the IMO through procurement markets. Must-run contracts for reliability can involve compensating a generator for staffing and keeping a unit in production mode as a support or contingency regardless of the market-clearing price on the spot market. The costs of providing these services are charged by the service provider to the IMO, which passes the expense to consumers through uplift charges. The IMO arranges suppliers for these services through a competitive tendering process. Contracts are limited to terms of 18 months or less for contracted ancillary services and 12 months or less for must-run contracts. These suppliers receive compensation for costs for being available, out-of-pocket costs, opportunity costs when providing the service and any other compensation deemed fair by the appropriate regulatory authorities.

The wholesale market design contemplates the creation of a real-time capacity reserve market that has not yet been implemented.

In its capacity as the independent electricity system operator, the IMO entered into operating agreements with transmission owners who continue to operate their systems, subject to IMO direction and regulation by the OEB. The IMO assesses transmission system constraints in its dispatch of energy and manages congestion and line losses using the established Market Rules. It also administers the grid connection requirements applicable to market participants connected to the transmission system and identifies any long-run security and adequacy requirements by conducting periodic long-run assessments. In addition, the IMO advises the OEB and participates in OEB proceedings that consider new transmission investment proposals. Market participants are free to present transmission investment proposals to the OEB at any time, with or without a supporting assessment from the IMO. The cost of new transmission system investments will be included in a network service charge unless the OEB determines that there is an identifiable beneficiary who should pay.

The IMO also collects the transmission service charges designed to recover the transmission owners' OEB-approved revenue requirements and disburses these revenues to the transmission owners. Consumers of significant amounts of electricity could, individually or as a group, build their own generation facilities and thereby avoid paying certain transmission charges. In many circumstances, consumer-owned generation will also allow those consumers to avoid IMO uplift charges. This could give rise to the construction of new generation capacity that would not be economic if it were not for this avoidance of transmission charges and IMO uplift charges.

Through its independent market surveillance panel, the IMO will identify and report on any inappropriate market conduct and market inefficiencies. In its first monitoring report issued October 2002, the MSP stated that there was no evidence of market power abuse. The IMO collects from and provides information to market participants relating to the current and future electricity needs of Ontario and the capacity of the integrated power system to meet those needs.

If the IMO determines prior to issuing dispatch instructions that market responses will not eliminate an under-generation condition, it can declare an emergency operating state to resolve the conditions. The IMO also has the authority to suspend the IMO-administered market if certain emergency circumstances exist or are imminent, such as a failure of the market system or a major blackout. The market cannot be suspended solely because the market price has reached the maximum market clearing price or some demand has been curtailed. Each market participant is required to file with the IMO its emergency plans to assist the IMO in dealing with an emergency operating state. The IMO will endeavour to restore market operations as soon as the conditions requiring suspension are resolved.

The OEB licenses the IMO and monitors its operations. The OEB also issues directions to the IMO and hears appeals of certain actions or decisions of the IMO, including any amendments to the Market Rules. The

IMO's operating costs are recovered through OEB-approved fees which are levied on the market participants. Bill 210 gave the Minister of Energy the power to review rule amendments before they are implemented and oversee certain rates approved by the OEB.

OEB's Licensing Process and Industry Codes

The OEB has developed licences for electricity generation, transmission, distribution, wholesale and retail. It has also developed several associated codes for retailing, transmission and distribution. The OEB issued a transitional generation licence to OPG that will remain in force until April 30, 2003. OPG has also received its wholesaler licence and retailer licence, which will remain in force until January 2006 and September 2005, respectively.

Market Power Mitigation

When the electricity market opened for competition, OPG owned (excluding assets leased to Bruce Power) approximately 73% of the generating supply options in Ontario. To address the possibility that OPG could exercise market power after the commencement of Market Opening, the Province approved a framework known as the "market power mitigation" framework to protect the interests of consumers while ensuring an orderly and gradual transition to a long-run industry structure in which OPG's share of generating capacity available to the Ontario market is substantially reduced. The market power mitigation obligations applicable to OPG are set out in the conditions to OPG's generation licence.

Rebate Mechanism and Transitional Price

The majority of OPG's expected energy sales in Ontario are subject to an average annual revenue cap of 3.8 cents per kWh which is not adjusted for changes in the consumer price index, fuel prices, labour or other price increases. During each 12 month period following May 1, 2002, if the average spot market price as calculated under the framework exceeds 3.8 cents per kWh, OPG is required to pay a rebate, which after April 30, 2003 will be paid quarterly, to the IMO equal to the difference between the average spot market price and 3.8 cents per kWh, multiplied by the quantity of electricity to which the threshold applies in that period, referred to as the contract required quantity ("CRQ"). This rebate amount is subject to reductions in the event of system price spikes, the carrying forward of a rebate credit from prior years and *force majeure* events. The IMO is responsible for allocating the rebate to Ontario consumers in the case of customers above the 250,000 kWh per year threshold and in other cases to the OEFC, on the basis of energy withdrawn from the IMO-controlled grid.

This rebate mechanism applies only to OPG. It does not guarantee that the spot market price will be 3.8 cents per kWh, nor does it set the price for individual consumers. Rather, OPG is free to offer electricity in to the power pool at whatever price it chooses, as are competing generation companies. The rebate mechanism applies to OPG's production up to the CRQ and is calculated as if OPG had produced at least the CRQ regardless of OPG's actual production. The CRQ has been predetermined for the period up to 2004 and varies over that period within a range of approximately 102 to 106 TWh, subject to reduction with the approval of the OEB as OPG decontrols its generation capacity. Assuming the Bruce and Mississagi transactions are determined to be decontrol by the OEB, the CRQ would be reduced by approximately 20.4 TWh for each applicable settlement period.

As noted earlier, effective from May 1, 2003, customers above the 250,000 kWh per year threshold will be entitled to receive a quarterly rebate payable through the IMO which is fixed at 50% of the amount by which the average spot price exceeds 3.8 cents per kWh. As described above, OPG's rebate commitment is impacted by the level of decontrol and therefore can fluctuate.

In addition, the Province enacted a regulation to provide transitional price relief to current customers of OPG that had contracted to purchase some or all of their electricity requirements under one or more of pricing options historically provided by Ontario Hydro to certain customers (being the Surplus Power, Real Time Pricing I, Real Time Pricing II and Load Retention and Expansion Price rate options) during a reference period from July 1, 1999 to June 30, 2000. Forty-five large power consumers with 68 sites have accepted this transitional price relief. OPG is required to effectively offer for sale to these customers a volume of energy based on their consumption of special rate power during the reference period. Price is based on the average price paid by each customer during the reference period. The anticipated volume is approximately 5.4 TWh in the first year after May 1, 2002; 3.6 TWh in

the second year and 1.8 TWh in each of the third and fourth years. The maximum length of the program is four years, with the possibility that it will expire after only two years if certain decontrol targets are met by OPG.

Decontrol of Capacity

Another market power mitigation measure requires OPG to relinquish effective control of some of its generating capacity. This may be accomplished by OPG through various transactions and could be done in a variety of ways, including the outright sale or lease of power stations or by entering into other arrangements provided the result is that OPG transfers control of the timing, quantity and bidding of energy produced by OPG's power stations. OPG's decontrol targets are specified in terms of Tier 1 and Tier 2 capacity. "Tier 1" capacity is defined as all nuclear and hydroelectric generation in Ontario. "Tier 2" capacity is defined as that portion of Ontario's generation capacity, including fossil generation, inter-tie capacity and demand-side bidding, that is not part of Tier 1 capacity. Within 42 months after May 1, 2002, OPG is to reduce its share of in-service Tier 2 generating capacity through transfer of effective control of a minimum of 4,000 MW of in-service Tier 2 capacity. At OPG's discretion, it may substitute the transfer of effective control of up to 1,000 MW of hydroelectric power in place of an equivalent amount of Tier 2 capacity. Within 10 years after May 1, 2002, OPG is to reduce its effective control of total Tier 1 and Tier 2 capacity to 35% or less of the supply options in the Ontario market. At the end of 2002, OPG controlled approximately 65% of total Tier 1 and Tier 2 based on the assumption that the Bruce and Mississagi transactions are decontrol transactions approved by the OEB.

Upon OPG's request, the OEB is required to make a determination as to whether a transaction represents the transfer of effective control and can therefore count towards OPG's decontrol targets and reduce the CRQ. Transfers of Tier 1 and/or Tier 2 capacity will not count towards OPG satisfying its targets or reducing the CRQ if (i) such transfer would result in any one transferee controlling more than 25% of the total relevant capacity in Ontario; or (ii) OPG and the transferees have in place any on-going arrangements which facilitate interdependent behaviour.

In keeping with its decontrol obligations, OPG has leased its Bruce A and B nuclear generating stations to Bruce Power L.P. in a transaction which closed on May 11, 2001. In a transaction that closed in February 2003, the ownership of Bruce Power L.P. was transferred to a consortium comprised of TransCanada PipeLines Limited, BPC Generation Infrastructure Trust, the Ontario Municipal Employees Retirement Board and Cameco Corporation. In addition, OPG sold the Mississagi hydroelectric stations to Mississagi Power Trust in a transaction which closed on May 17, 2002. OPG has announced that it also intends to decontrol its Lakeview, Lennox, Thunder Bay and Atikokan facilities. These assets are still available for decontrol, however the prospects for a successful transaction are likely to be influenced by a variety of factors including limited access to the capital markets, an excess supply of generating assets in the marketplace and the risk of changing environmental regulations. See *"Business of OPG – Generation Operations – Fossil Operations – Fossil Station Decontrol"*.

Import Restrictions

OPG's ability to import power from interconnected markets is restricted to 7.24 TWh in the winter season and 6.58 TWh in the summer season. These restrictions are intended to ensure that OPG does not exercise market power by controlling imports across the interconnection points. These import limits will be increased upon the in-service date of new or upgraded interconnection facilities. Ontario's inter-tie capacity is currently approximately 4,000 MW. Hydro One is obligated under its licence conditions to use its "best efforts" to expand inter-tie capacity to neighbouring jurisdictions by approximately 2,000 MW within 36 months of May 1, 2002. Hydro One has obtained the approval of the OEB to begin their portion of the work to expand the existing Ontario-Québec inter-tie by 1,250 MW. Hydro-Québec, however, is still in the process of resolving its regulatory issues for the project and therefore the outcome of this project is still uncertain. The expansion is scheduled to be constructed by late 2005. In addition, Hydro One is completing the installation of phase-shifting transformers and an autotransformer at its interconnection with the Michigan power grid. Depending upon how the phase shifters will be operated, this equipment should provide the ability to better control energy flows at that interconnection point and, indirectly, at the interconnection with the New York power grid. The equipment is expected to increase the available transfer capability between Ontario and Michigan by 500 - 600 MW.

Operating Reserve

Under the market power mitigation conditions of its generation licence, offers made by OPG to provide operating reserve to the IMO are capped. The level of this cap includes the actual cost of providing operating reserve, such as additional operating and maintenance costs, additional fuel costs, additional opportunity costs and a reasonable rate of return on incremental capital. OPG will receive the clearing price for operating reserve regardless of how that price is set. OPG is required to offer all available capacity into the operating reserve market, consistent with good utility practices.

OEB Review

Forty-two months following May 1, 2002, the OEB will review and publicly report on OPG's success in attaining its decontrol target respecting Tier 2 capacity, as well as upon its plans for meeting its 10-year decontrol target. If the 42-month targets are not met, the Board is to advise the Minister on a range of mechanisms which may be used to achieve a stable, structural solution to market power through to the end of the 10 years. If the 42-month targets are met, the OEB will advise the Minister on the appropriateness and term of ongoing price controls over OPG's Tier 1 generation for the fifth through tenth years without altering the 10-year decontrol target. The OEB will conduct a further review in the seventh year following May 1, 2002 to determine OPG's progress in meeting its 10-year decontrol target. OPG will be required to file annual reports with the OEB in years five through nine following May 1, 2002 on its progress toward meeting this target.

Environmental Regulation

OPG is subject to federal, provincial and municipal environmental laws. These include laws relating to the control of discharges to air, land and water, as well as the investigation and remediation of contaminated property and the management and disposal of materials and hazardous wastes, including nuclear wastes. The Federal Government has also entered into various international environmental agreements, some of which may affect OPG, such as the Kyoto Protocol. See "*Business of OPG – Environmental Matters*".

The principal Provincial environmental laws that apply to OPG are Ontario's *Environmental Protection Act* (the "EPA"), the *Ontario Water Resources Act* (the "OWRA"), the *Environmental Assessment Act* (the "EAA"), the *Dangerous Goods Transportation Act* (which incorporates, by reference, the Federal *Transportation of Dangerous Goods Act Regulations*) and the *Technical Standards and Safety Act*, as well as regulations made under these statutes, including EPA Regulation 346 (air emissions), EPA Regulation 215/95 amended to 501/99 (the "MISA Regulation"), EPA Regulation 347 amended to 501/01 (general waste management), EPA Regulation 356 (ozone depleting substances or "ODS"), EPA Regulation 362 (polychlorinated biphenyls or "PCB" wastes), EPA Regulations 153/99 and 397/01 (which regulate SO_2 and NO_x emissions from OPG's fossil-fuelled generating stations and the procurement and use of emission reduction credits and allowances), EPA regulation 396/01 (which regulates nitric oxide emissions at the Lakeview fossil generating station) and EPA Regulation 127/01 amended by 196/01 (which requires all facilities in the electricity sector to monitor and report on the emissions into the atmosphere of a number of substances).

The EPA and regulations made thereunder regulate the management and disposal of wastes (including hazardous and non-hazardous wastes), discharges and spills into the natural environment, liquid effluent discharges into water and emissions into the air. OPG is required under the MISA Regulation to ensure that liquid effluents discharged directly into water bodies are within specified toxicity limits. The OWRA imposes obligations to protect the quantity and quality of water in Ontario. Specifically, the OWRA forbids any discharge of material into water that may impair the quality of water.

There are two existing Director's Orders issued to OPG by Ontario's Ministry of Environment and Energy pursuant to the EPA. One requires OPG to measure SO_2 and NO_x emissions using Continuous Emissions Monitors ("CEMs") and the other requires OPG to determine whether there is contaminated property at the generating stations and to take remedial action, if necessary. See "*Business of OPG – Environmental Matters – Overview*" and "*– Contaminated Land*".

The principal Federal environmental laws that apply to OPG are the *Canadian Environmental Protection Act, 1999* ("CEPA, 1999"), the *Fisheries Act* and the *Navigable Waters Protection Act*. CEPA, 1999 regulates the use, storage, import and export of toxic substances, such as ODS and PCBs. The *Fisheries Act* prohibits the

alteration or destruction of fish habitat and prohibits the deposit of any substance that would be harmful to water that may be inhabited by fish. An authorization under the *Fisheries Act* is required for the construction of a project that would result in the harmful alteration or destruction of fish habitat. Under the *Navigable Waters Protection Act*, approvals are required for the construction of works that interfere with the public right of navigation and the alterations to the originally approved work.

The Federal *Canadian Environmental Assessment Act* requires an environmental assessment of certain projects such as those requiring certain federal regulatory actions, including CNSC licences for the construction of nuclear facilities or approval of the disposal of nuclear substances and approvals for projects affecting navigable waters or that impact fisheries. The *Canadian Environmental Assessment Act* may apply to some of OPG's facilities, including its nuclear facilities and hydroelectric modifications or developments that affect navigation or fish habitat. An environmental assessment under the *Canadian Environmental Assessment Act* was completed for the restart of Pickering A, for dry storage at Bruce B and Pickering A, and one is currently underway at Darlington for its used fuel dry storage facility project. See "*Business of OPG – Generation Operations – Nuclear Operations – Nuclear Recovery Plan*".

Ontario's *Environmental Assessment Act* traditionally required that only projects initiated by public bodies (which were listed in the regulations and included OPG) be assessed and approved under the EAA. Therefore, OPG was historically required to conduct full environmental assessments of all projects, including new developments or facility modifications and obtain Ministry of Environment and Energy approval, unless otherwise exempted. Private sector companies were not subject to the EAA, except if a project was specifically designated for an environmental assessment. New regulations under the EAA have changed the environmental assessment requirements to apply equally to projects by both public and private sector electricity companies. These new regulations divide projects into three general categories, depending on the predicted impact of the project on the environment, with either no environmental assessment requirements, screening level environmental assessment requirements, or requirements for a full environmental assessment.

Energy Regulation

The OEB Act, 1998 authorizes the OEB to operate as an independent, quasi-judicial, regulatory agency of the Province and to regulate the electricity industry. The Corporation is licensed by the OEB as an electricity generator, retailer and wholesaler. See *"– Ontario's Electricity Industry – Legislation"* and *"Ontario's Electricity Industry – OEB Licensing Process and Industry Codes"*.

The *National Energy Board Act* (Canada) established the National Energy Board (the "NEB"), an independent Federal regulatory agency that regulates, among other things, the construction and operation of international and designated interprovincial power lines and the export of electricity into the United States. OPG holds permits issued by the NEB for the export of electricity into the U.S. The most significant of these permits provides for the export of up to 25 TWh of power in any consecutive 12-month period.

In the United States, regulation of electricity is shared among FERC and the Department of Energy, at the Federal level and the State Public Service Commissions, at the State level. FERC has jurisdiction over transmission used in interstate commerce and rate-setting authority over wholesale transactions. The Department of Energy issues presidential permits authorizing the construction of international power lines and permits authorizing the export of electricity. The State Public Service Commissions have rate-setting authority over retail transactions and siting authority for most new facilities. Each State also retains the authority, either through its Public Service Commission or its legislature, to determine if and when open retail access will be permitted.

On April 11, 2002, Ontario Energy Trading International Corp. ("OETI") (a wholly-owned U.S. subsidiary of the Corporation) received authorization from FERC to buy and sell electricity to wholesale customers in the United States at market-based rates (a "power marketer's licence"). This authorization does not limit the volume of transactions that OETI can enter into, nor does it contain any geographic limitations. In determining whether to issue a power marketer's licence, FERC considers whether the seller has adequately mitigated its generation market power in the United States and whether the seller or any of the seller's affiliates that own transmission facilities has adequately mitigated its transmission market power by providing, for example, open access transmission service consistent with FERC Orders Nos. 888 and 889. In approving OETI's FERC application, FERC has therefore determined, in part, that the Ontario market offers wholesale open access comparable to that provided by U.S.

transmission systems under Order 888. This finding, therefore, permits OPG as well as any subsidiary to purchase transmission services in the United States. OETI has also received authorization from the U.S. Department of Energy for an export permit. This permits OETI to export electricity from the United States into Canada.

FERC's decision to extend market-based rate authority to OETI has been challenged by Consumers' Energy of Michigan. The decision is currently subject to review by FERC pursuant to a Petition for Rehearing and also by the DC Circuit of the U.S. Court of Appeals. However, the market-based rate authority remains in effect while any appeals are heard.

Nuclear Regulation

The *Nuclear Safety and Control Act* (Canada) (the "NSC Act") created the Canadian Nuclear Safety Commission (the "CNSC") and authorized it to make regulations governing all aspects of the development and application of nuclear energy. The most significant powers given to the CNSC are in the licensing area. A person or organization may only possess or dispose of nuclear substances and construct, operate and decommission its nuclear facilities in accordance with the terms of a licence issued by the CNSC. The licence specifies conditions that licensees must satisfy in order to demonstrate that the licensee is qualified to carry out the activities authorized by the licence. International and national standards in relation to matters such as safeguards and radioactive emissions are examples of conditions incorporated into station licences.

A fundamental principle in nuclear regulation is that the licensee bears the responsibility for safety, with the CNSC setting safety objectives, including radiation protection, physical security for all nuclear generating stations and the transport of radioactive materials, and auditing the licensee's performance against the objectives. The CNSC has also issued guidance documents to assist licensees in complying with regulatory requirements as these apply to containment and shutdown system operation for CANDU nuclear generating stations. Requirements spelled out in these guidance documents have been incorporated into the operating documents for OPG's nuclear generating stations.

The NSC Act is the product of a recent update of regulatory requirements by the Federal Government in relation to the effective regulation of nuclear energy in Canada. The NSC Act grants to the CNSC the power to act as a court of record, the right to require financial guarantees for nuclear waste management and decommissioning as a condition of granting a licence, order-making powers which are more flexible than those allowed under the predecessor legislation, the *Atomic Energy Control Act* and the right to impose higher monetary penalties for licensing infractions. The NSC Act also grants the CNSC power to require periodic re-certification of nuclear operators and to set requirements for servicing licences and various nuclear facility security measures. The NSC Act also provides for increased emphasis on environmental matters, including a requirement that licensing applicants make adequate provision for the protection of the environment. The NSC Act grants the CNSC licensing authority for all nuclear activities in Canada, including the issuance of new licences to new operators, the renewal of existing licences and amendments to existing licences.

The *Nuclear Liability Act* (Canada) (the "NLA") imposes absolute liability on a licensed operator of a nuclear generating station for any damage to property of, or personal injury to, the public arising from a nuclear incident other than damage resulting from sabotage or acts of war. As such, the NLA protects suppliers of nuclear fuel and components used in nuclear reactors. The NLA bans an operator from suing any person in respect of its liability under the legislation, except persons responsible for acts of sabotage.

The NLA requires all operators of nuclear generating stations in Canada to purchase nuclear liability insurance from the Nuclear Insurance Association of Canada in specified amounts. Currently, the NLA requires a nuclear operator to maintain, for each of its nuclear stations, insurance up to a limit of $75 million per incident against the liability imposed under the NLA. Under Part I of the NLA, an operator is liable for all damages resulting from a nuclear incident. If in the opinion of the Governor in Council, an operator's liability could exceed $75 million in respect of a nuclear incident, or it would be in the public interest to do so, the Governor in Council must proclaim Part II of the NLA as applicable in respect of a nuclear incident. Under Part II of the NLA, an operator's liability would be effectively limited to the amount of such insurance and the Governor in Council may authorize additional funds to be paid by the Federal Government as may be specified in an order. The NLA is currently under review, which could result in a requirement for increased insurance coverage. See *"Business of OPG – Insurance"*.

Since the regulation of nuclear energy could have transboundary impacts, Canada has become a signatory to various international conventions relating to nuclear energy and emergency responses and is bound by conventions that it has ratified. In addition, the CNSC has entered into a five-year, bilateral information exchange and co-operation agreement with the U.S. Nuclear Regulatory Commission, which provides among other things, for the prompt, reciprocal notification of reactor safety problems that could affect both U.S. and Canadian nuclear generation facilities.

All of OPG's nuclear power reactor operating licences were reissued as of April 1, 1999 when OPG acquired the generation business of Ontario Hydro. All nuclear power reactor operating licences have since been renewed pursuant to the *Nuclear Safety Control Act* by the CNSC. On February 25, 2003, CNSC granted a five year renewal of the operating licence for the Darlington generating station. CNSC staff also recommend to the Commission that licence for each of Darlington and Pickering B be renewed for a period of 5 years. A decision, in this regard, has not yet been made by the Commission but is expected after the next hearing of this matter on May 21, 2003. For Pickering A, which has been laid up since the end of 1997, the CNSC staff have recommended a licence renewal for a period of 2 years. A decision in this regard, is also expected after the next Commission hearing of this matter on May 21, 2003. Renewal of these licences is subject to a variety of terms and conditions relating to the operation of the facilities. The Pickering A operating licence currently contains a clause which restricts operation of the units subject to approval of the CNSC to restart the Pickering A units.

See also "– *Provisions for Nuclear-Related Costs*" for information about the *Nuclear Fuel Waste Act*.

Water Rights

Hydroelectric generation requires ongoing access to an adequate water supply on reasonable terms. The physical availability of water is affected by numerous facts including variations in precipitation, sublimation and evaporation. Rights to and restrictions on the use of water are determined through international treaties, federal and provincial legislation, common law and leases, licences, permits and agreements with the Federal Government, the Province, neighbouring provinces, municipalities, other utilities and other water users.

There are three main federal and provincial statutes governing OPG's water rights or use of water in Ontario, being; (i) the *Public Lands Act* (Ontario) which grants jurisdiction to the Ministry of Natural Resources ("MNR") to regulate the management, sale and disposition of public lands and forests. OPG has water power leases, water lot leases, licences of occupation, land use permits and Crown leases for the purpose of generating electricity; (ii) the *Lakes and Rivers Improvement Act* (Ontario) which regulates the use of the lakes and rivers of Ontario. This statute is administered by the MNR and provides for the preservation and equitable exercise of public rights and natural amenities over water. The MNR authorizes the design, construction, operation, maintenance and safety of structures on lakes and rivers in Ontario such as dams, bridges and docks; and (iii) the *Navigable Waters Protection Act* (Federal) which regulates the construction of facilities that may impact or effect navigation on a navigable waterway.

International Rivers

Seven of OPG's hydroelectric generating stations are directly or indirectly supplied by two major international waterways, the Niagara River and the St. Lawrence River, and are subject to treaties with the United States relating to water use. Those stations represent approximately 48% of OPG's in-service hydroelectric capacity and approximately 55% of OPG's 2002 hydroelectric generation.

A 1909 treaty with the United States (the "Boundary Waters Treaty") governs the rights of Canada and the United States over all lakes, rivers and connecting waterways along the international boundary. A 1950 treaty between Canada and the United States (the "Niagara Diversion Treaty") supersedes the Boundary Waters Treaty with respect to diversions of the Niagara River for power generation purposes. The Boundary Waters Treaty has been terminable by either party on 12 months' notice since 1915 and, in 2000, the Niagara Diversion Treaty became terminable by either party on 12 months' notice. Given the significant interests of both countries in the water rights which are contingent on the continued effect of these treaties, OPG does not expect Canada or the United States to exercise their termination rights under either treaty in the foreseeable future. OPG is not aware of any negotiations concerning formal extensions or replacement treaties.

Each of these treaties grants Canada and the United States equal rights to use waters made available for power generation, subject to certain water use restrictions. Additional water is allocated to Canada under the Niagara Diversion Treaty and is used by OPG's Niagara hydroelectric operations to account for water that is diverted to the Niagara system via Lake Superior from the James Bay watershed by the Ogoki and Long Lake Diversions in northern Ontario. Canada's rights and obligations under each treaty that relate to power generation on the Great Lakes and the St. Lawrence River are exercised by the Province, which has in turn granted certain of those rights to OPG under legislation and lease agreements.

OPG's operations on the Niagara and St. Lawrence rivers are conducted in accordance with memoranda of understanding with the New York Power Authority which provide for co-ordinated generation at their respective facilities and for certain cost sharing arrangements.

OPG's use of water from the Niagara River, the Welland River, the Welland Canal and the St. Lawrence River is monitored and controlled by international organizations established under the applicable treaty. These organizations have the authority to set operational limits for flows and elevations associated with water power generation in order to maintain adequate water availability for domestic and sanitary uses and for navigation and to minimize negative impacts on other users of these rivers. The amount of water available from the Niagara River for power generation is subject to additional limits to ensure adequate flow over Niagara Falls for scenic purposes.

Niagara Region

Through a combination of statutory rights and a lease agreement with the Niagara Parks Commission that expires in 2056 (subject to certain renewal rights), OPG has the right to divert water from the Niagara River and construct facilities to generate power. OPG has four stations that use water diverted from the Niagara River and two stations that use water from the Welland River and Welland Canal. Together, these stations represent approximately 33% of OPG's in-service hydroelectric capacity and approximately 35% of OPG's 2002 hydroelectric generation.

Under a Niagara Parks Commission agreement which, subject to certain rights of the Province, expires in 2009, the Rankine hydroelectric generating station operated by Canadian Niagara Power Company Limited ("CNP") is entitled to withdraw water from the Niagara River, as part of Canada's share of water under the Niagara Diversion Treaty, in an amount equal to that required for the generation of electrical power to a daily average not exceeding 100,000 electrical horsepower (provided that at no time shall the amount produced exceed such daily average by more than three percent). Under an agreement between OPG and CNP, CNP consents to OPG using CNP's water entitlement. OPG is currently negotiating with CNP regarding these water rights.

The DeCew Falls stations use water that is transported along the Welland Canal from Lake Erie by the St. Lawrence Seaway Management Corporation under an agreement that expires in 2008, but which is renewable to 2038.

St. Lawrence River

The R.H. Saunders station near Cornwall represents approximately 15% of OPG's in-service hydroelectric capacity and approximately 19% of OPG's hydroelectric generation in 2002. By statute, the Province has granted to OPG the right to use water from the International Rapids section of the St. Lawrence River for power generation, subject to an agreement between Canada and the Province that requires the Province to construct, maintain and operate the works in accordance with conditions or orders imposed by Canada or the international organization established under the Boundary Waters Treaty. Canada has the right, upon notice and after unsuccessful arbitration, to take over the operation of and title to, the R.H. Saunders station in the event of a breach of the agreement by the Province.

Interprovincial Rivers

Four of OPG's hydroelectric stations are located on the Ottawa River which forms part of the Ontario-Québec border. These stations represent approximately 13% of OPG's in-service hydroelectric capacity and approximately 13% of OPG's 2002 hydroelectric generation. Three of OPG's Ottawa River stations are subject to 999 year leases with each of the Province of Ontario and the Province of Québec and the fourth is subject to a water power lease with the Province of Ontario which is renewable, subject to certain conditions, through to 2031. OPG's use of water from the Ottawa River basin is subject to guidelines established by a board comprised of government and industry representatives.

The operations of certain of OPG's stations in northwestern Ontario can impact users in Manitoba and are subject to guidelines and directions provided by a board comprised of Ontario and Manitoba government representatives. These sites are included under "– *Interior Rivers*".

Interior Rivers

Fifty-four of OPG's 64 hydroelectric stations (including 29 green energy), representing approximately 39% of OPG's in-service hydroelectric capacity and 32% of OPG's hydroelectric generation in 2002, are located on 22 other Ontario river systems. OPG holds water power leases and licences with the Province on the river systems that supply 36 of these stations. These leases and licences have expiry or renewal dates ranging between 2012 and 2075. Certain of these leases provide that the leased property and any fixed improvements, including the generating stations and the dams, will revert to the Province on the expiry of the lease. The 36 stations covered by these licences and leases represent approximately 38% of OPG's in-service hydroelectric capacity. Approximately 1% of OPG's in-service hydroelectric capacity comes from the remaining 18 stations.

OPG's use of Ontario's interior watersheds is constrained by restrictions contained in certain water power leases and licences. OPG also operates within voluntary guidelines established on a watershed basis in consultation with the MNR, federal fisheries authorities and stakeholders such as recreational and commercial users, local communities, environmental groups and First Nations. Many of these guidelines will become formal obligations through the water management planning process initiated by the MNR under its "New Business Relationship" with the water power industry and subsequent amendments to the *Lakes and Rivers Improvement Act*.

Environmental Matters

Overview

OPG's activities involve risk of adverse consequences to the environment and are subject to extensive governmental regulation. See *"Business of OPG – Regulation – Environmental Regulation"* and *"Business of OPG – Risk Factors – Environmental Risks"*. OPG is committed to becoming a sustainable energy development company. In accordance with this commitment, OPG strives to continually improve environmental performance in its operations and in its relations with stakeholders.

OPG's Sustainable Energy Development Policy commits OPG to meeting all applicable legislative requirements and voluntary environmental commitments, integrating environmental factors into business planning and decision-making and applying the precautionary principle in assessing risks to human health and the environment. This policy also commits OPG to maintain comprehensive environmental management systems ("EMSs") consistent with the ISO 14001 standard. OPG became one of the first electric utilities in North America to obtain ISO 14001 registration for the EMSs at all its generating stations in 1999/2000. This registration is obtained and kept current annually through independent audits.

OPG monitors emissions into the air and water and regularly reports the results to various regulators, including the Ministry of Environment, Environment Canada and the CNSC. OPG has implemented internal monitoring, assessment and reporting programs to manage environmental risks such as air and water emissions, discharges, spills, radioactive emissions and radioactive wastes. Further, OPG makes regular reports to the Ministry of Environment with respect to its contaminated land remediation program.

In addition to the regular reports made to various regulators, the public receives frequent communications from OPG regarding OPG's environmental performance through community-based advisory groups representing communities surrounding OPG's major generating stations, annual environmental performance reports, community newsletters, open houses and OPG's website.

Management of Air Emissions

OPG is required to comply with provincial and federal air quality requirements in connection with discharges into the air from its generating stations.

Hydroelectric Operations

There are no material environmental concerns relating to air emissions from hydroelectric operations.

Fossil Operations

The burning of fossil fuels gives rise to a number of air emissions, principally sulphur dioxide ("SO_2"), oxides of nitrogen ("NO_x") and carbon dioxide ("CO_2"), as well as mercury and particulate matter such as dust and ash. Acid gas (SO_2 and NO_x) emissions contribute to acid rain and legislation specifically regulating such emissions has been in force in Ontario since the mid-1980s. A number of government initiatives have been implemented or recently announced regarding air emissions and others can be anticipated to deal with this issue.

OPG's fossil generation is currently limited because Ontario's environmental regulations limit OPG's annual SO_2 and NO_x emissions, net of banked allowances and emission reduction credits retired. In order to meet these regulatory requirements, OPG has implemented air management initiatives to monitor and reduce emissions from its fossil generating stations. For a discussion of the regulatory regime applicable to SO_2 and NO_x air emissions as well as of OPG's initiatives to address these regulations, see "*Business of the Corporation – Generation Operations – Fossil Operations – Effective Generation Limits and Air Emissions*".

The United States Environmental Protection Agency has announced plans (the "State implementation plans") to require further air emission reduction measures to be in place in 22 eastern States by 2004, including those states within OPG's potential marketing area. The Ontario regulations applicable to Ontario power plants are consistent with the requirements of the State implementation plans, although the emission reduction timelines contemplated by the Ontario regulations are somewhat different than those in the State implementation plans.

The primary greenhouse gas resulting from OPG's operations is CO_2. Canada has ratified the Kyoto Protocol requiring a six percent reduction in greenhouse gas emissions from 1990 levels by the period 2008 – 2012. Prior to the ratification of the Kyoto Protocol, OPG voluntarily committed to reduce its greenhouse gas emissions, net of emission reduction credits used, to 1990 levels in 2000 and beyond. OPG continues to make modifications to equipment and operating controls that improve its coal combustion heat rate and improve the energy efficiency of all generating facilities, thereby reducing coal consumption and lowering CO_2 emission rates. The Federal Government's climate change plan calls for a 55 million tonne reduction in greenhouse gas emissions from large industrial emitters, which includes the electricity sector, by 2010. The reductions required from specific sources will be set out in covenants negotiated in 2003. OPG is preparing for these negotiations and will revise its greenhouse gas emissions target and strategy as required to implement the resulting covenant.

The Federal Government has attempted to reduce the economic impact of limits on greenhouse gas emissions from large industrial emitters by committing that industry will have access to CO_2 credits at a cost of no more than $15 per metric tonne, and by limiting the credit volume risk to no more than 15 % below business as usual emissions in 2010. See "*Business of OPG – Risk Factors – Environmental Risks*".

Mercury emissions from coal-fired generating stations are emerging as an environmental and health issue. Initiatives are underway in both Canada and the United States to assess and regulate mercury emissions from the electricity generating sector. Specifically, the United States Environmental Protection Agency has announced plans to develop a final electricity sector mercury regulation in 2004 with compliance to be achieved in 2007. In Canada, a voluntary mercury monitoring and reporting program is planned which would provide mercury emission data to support the development of a Canada wide mercury standard. There is considerable uncertainty as to what specific standards will be established for permitted mercury emissions in part because currently available technologies are expensive, unproven in commercial applications and may not result in the permanent removal of mercury from the environment. Other technologies are being reviewed but are not yet proven. At this stage OPG has been actively involved in researching and funding the development of mercury emission control technologies. OPG also continues to work with government, stakeholders, academics and industry in addressing mercury emissions.

Nuclear Operations

As a condition of licensing, all nuclear operations are equipped with radiation emission monitors to ensure that emissions are below regulated limits. All nuclear operating licences stipulate limits on the rates at which radionuclides may be emitted to the air from each nuclear site. These derived emission limits are site-specific and approved by the CNSC. Since the 1970s, actual radiological air emissions from OPG's nuclear facilities have remained a small fraction of the regulatory limit set for each radionuclide.

OPG reports annually on the results of its radiological environmental monitoring programs at each nuclear generating station that estimate the radiation exposure to persons who are assumed to live immediately outside the station fence. This theoretical dose has consistently been estimated to be a small fraction of the public dose regulatory limit set by the CNSC. The results of these monitoring programs are reported on an annual basis to the CNSC, the Ministry of Environment and the municipalities in which the nuclear stations are located. They are also reported quarterly in the nuclear report cards that are made available to the public.

All Operations

OPG has a corporate policy to manage ozone-depleting substances ("ODS") in a safe, environmentally responsible and cost-effective manner. ODS, including chlorofluorocarbons ("CFCs") and halons, are used in refrigeration systems and fire fighting systems and can damage the ozone layer if emitted to the atmosphere. The Federal Government has proposed regulations that will accelerate the transition from CFCs and halons to alternative substances and technologies beginning in 2005. OPG estimates that this proposed regulatory change may result in replacement costs of approximately $10 million. At OPG, CFCs are no longer used in mobile vehicle air conditioning systems. All halon fire extinguisher systems have been replaced at the generating stations and all portable halon fire extinguishers have been removed from service.

Management of Water Effluent

OPG is required to comply with federal, provincial and municipal water quality requirements in connection with the discharge of condenser cooling water and other water effluents from OPG's generating stations.

Fossil Operations

OPG has implemented programs to manage the water effluent from its fossil generating stations and is in material compliance with Ontario's MISA Regulation (O. Reg 215/95 as amended).

OPG uses chlorine to control zebra mussels at some of its fossil stations. OPG's exemption from the provincial regulatory limits in the power sector MISA Regulation relating to chlorine-induced toxicity from chlorine used to control zebra mussels expired in July 2002. OPG has spent approximately $15 million in the aggregate for dechlorination of effluent from fossil facilities, including upgrades to the chlorination systems. This work was completed in advance of the July 2002 deadline.

Nuclear Operations

OPG has implemented programs to manage the water effluent from its nuclear generating stations. At the end of 2001, OPG had spent about $120 million to install new equipment at its nuclear generating stations in order to comply with the power sector MISA Regulation. Like the fossil stations, the nuclear operations use chlorine to control zebra mussels. See *"– Fossil Operations"* above. OPG has spent approximately $7.0 million at its nuclear facilities to achieve compliance with the MISA Regulation chlorine-toxicity requirements which came into force in July 2002.

OPG has replaced the brass condensers at Pickering B nuclear station, which were a source of copper/zinc contamination from that station. The Pickering A brass condensers will be replaced before they are returned to service. The estimated cost of completing the condenser tube replacements at Pickering A is $38 million.

Contaminated Land

The Ministry of Environment and Energy issued a Director's Order (the "Order") in September 1997 requiring that Ontario Hydro report on tritium contamination at the Pickering nuclear generation station and assess potentially contaminated lands at its other generating facilities. In response to the Order, all of OPG's known and potentially contaminated properties were ranked according to potential risk to human health and the environment in order to develop priorities for corrective action. Focusing on the high priority sites, OPG prepares an annual site assessment plan, which is submitted to and approved by the Ministry of Environment. The site assessment plan provides a progress report and plans for the current year to address the Order. All commitments made in the site assessment plans for the past six years have been met.

Since 1997, the number of high priority sites covered by the Order has been reduced from 50 to two as of January 23, 2003. As of December 2002, the Ministry of the Environment had provided written confirmation that OPG had fulfilled its site assessment requirements under the Order for all high, medium and low priority sites at its fossil and hydroelectric generating facilities. Remediation of these sites is now in progress where required. Reports on the extent of contamination and risk assessment for the two remaining high priority areas at the Pickering nuclear generating station, which warranted detailed investigation, were submitted to the Ministry of Environment. These reports and the independent third party reviews required by the Order are being considered by the Ministry of the Environment to determine remedial action. Remediation at one other high priority nuclear site is in progress. The Ministry of the Environment confirmed in August 2002 that the requirements under the Order had been met for all medium and low priority sites at OPG facilities. These are being assessed or remediated as required under OPG's voluntary environmental site assessment program.

One additional site, a reservoir not covered by the Order, Lake Gibson, is currently being assessed under a parallel voluntary program. OPG estimates the present value of assessment and remediation of all contaminated sites (including Lake Gibson) at approximately $44 million over the next five years and such amount is fully reserved in the OPG balance sheet. The need for remediation of the Lake Gibson reservoir has not been established as OPG is not the source of the contamination. See "*Business of OPG – Regulation – Environmental Regulation*".

In addition to the above, costs for demolition and site clean up of facilities at Kipling Avenue, Orde Street and 700 University Avenue in Toronto, including assessment and remediation, are estimated at $7 million. These costs are reserved under the OPG environment provision.

Management of PCBs

PCBs have been widely used for a number of industrial applications and particularly as a coolant and insulating fluid in electrical equipment (for example, in transformers and capacitors). Since 1977, PCB production has been prohibited in North America. In 1998, Ontario Hydro made a policy commitment to eliminate 81% of its in-storage PCB waste and in-service high-level PCBs by December 31, 2005 and the remainder of in-service high-level PCBs by December 31, 2015. As of December 31, 2002, the amounts of PCBs at the fossil, nuclear and hydroelectric stations were 625 tonnes, 803 tonnes and eight tonnes, respectively, consisting of in-service high-level PCB transformers and small amounts of PCB waste to be shipped for destruction. Revisions to the federal PCB regulations anticipated for the fall of 2003 are expected to call for the phase-out of all high-level (over 500 parts per million) in-service PCB equipment by the end of 2007 and all low-level (between 50-500 parts per million) PCB equipment by the end of 2014. The proposed changes will have no material effect on OPG.

At OPG's hydroelectric facilities, transformers with high-level PCBs have been removed from all facilities. There are no power transformers known to be in-service with low-level concentrations of PCBs. Minor quantities of PCB and PCB-contaminated equipment that remains in-service consists of lighting ballasts, cables, bushings and capacitors. PCB wastes were removed from OPG's hydroelectric facilities for decontamination and/or destruction commencing in 1995. There are approximately eight tonnes of PCB-contaminated equipment remaining at hydroelectric facilities. A preliminary estimate for the cost of disposal is $30,000.

At its fossil stations, OPG has removed substantially all low-level PCB equipment, materials and oil from in-service operating equipment. OPG plans to remove all in-service high-level PCB equipment from its fossil operations and ship such waste along with the currently-stored PCB waste for destruction in 2005. The total cost for replacement of this equipment is approximately $15.4 million. This cost and the ability to complete the removal of PCBs, will depend on the availability of PCB-destruction facilities, such as the Swan Hills facility in Alberta.

Substantially all of the previously accumulated in-storage PCB waste from OPG's nuclear stations has been destroyed. The Pickering A nuclear station has in-service high-level PCB transformers. OPG plans to phase out these transformers as part of the Pickering A return to service project at an estimated cost of $6.5 million. There are small quantities of PCBs in capacitors at Pickering B nuclear station and no in-service PCBs or PCB wastes at the Darlington nuclear station.

OPG's total projected cost for remaining PCB phase-out and equipment replacement at its fossil and hydroelectric stations and the Pickering A nuclear station is $21.9 million. Remaining costs of PCB phase-out and destruction, estimated at $6 million, are covered in the environment provision. The Bruce A station has in-service

high-level PCB transformers, but the cost of dealing with these will be borne by Bruce Power during the time it operates those facilities.

Nuclear Waste Management and Decommissioning

OPG has adopted certain management practices and planning assumptions to satisfy its nuclear waste management and decommissioning obligations. See *"Business of OPG – Generation Operations – Nuclear Operations – Nuclear Waste Management and Decommissioning"* and *"Business of OPG – Risk Factors – Nuclear Operations"*.

Legal Proceedings

OPG is currently a party to and its assets are the subject of various legal proceedings and OPG is aware that there are further proceedings contemplated. OPG does not believe that any of these is likely to have a materially adverse impact on the Corporation on a consolidated basis.

Risk Factors

Each of the following risk factors could have a material adverse effect on OPG's business, financial condition, operating results and prospects.

Restructuring of Ontario's Electricity Industry

Ontario's electricity market has been open to competition since May 1, 2002 with the introduction of competition in both the wholesale and retail markets in Ontario. The regulatory authorities responsible for the structuring, development and operation of the new Ontario electricity market, the IMO and OEB and many of the incumbent participants in the Ontario market, including OPG, have less than a year of operating experience in a competitive electricity marketplace. Accordingly, it is possible that further changes in the structure of the electricity industry may be necessitated as has been done with the implementation of Bill 210. These changes may be accomplished either through fundamental changes by the Province to the structure of the Ontario electricity industry, or through changes made by the IMO to the Market Rules. As a result, it is difficult to predict the effect of these changing market and regulatory conditions on OPG's business, operating results, financial position or prospects.

In certain jurisdictions where the energy marketplace has been opened to competition, factors such as episodes of energy price volatility and supply shortages have prompted a re-examination of the market framework by governments, regulatory authorities and consumer groups. In the U.S., FERC is attempting to achieve consensus for a standard market design for wholesale markets. Political, regulatory and consumer responses to the competitive electricity market in Ontario and certain developments toward re-regulation in parts of the North American electricity industry, could impact OPG and the successful implementation of OPG's business strategies and have a material adverse effect on its business, operating results, financial position or prospects.

Information Technology Infrastructure

OPG's ability to operate effectively and competitively in the Ontario electricity market is in part dependent upon OPG developing or subcontracting and managing a complex information technology systems infrastructure. Future system failures, or an inability to keep information technology systems aligned with changing market conditions and strategic business objectives, could have a material adverse effect on OPG's business, operating results, financial condition or prospects. See "*Human Resources*" and "*Business of OPG – Information Technology*". There is, however, a risk that these systems may not adequately manage all such risks.

Competition

OPG believes its ability to compete depends upon many factors within and outside its control, including: the entrance of new participants in the Ontario market; the competitive actions of market participants; the extent of self-generation; compliance with market power mitigation obligations; generation performance; changes in the regulatory environment; changes in environmental regulations; access to the interconnected markets; supply, demand and the cost of power in the interconnected markets; weather-related electricity demand levels; wholesale

and spot market electricity prices; reliability of supply; customer service and support; and sales and marketing efforts. There can be no assurance that OPG will be able to compete successfully in these circumstances or that competitive pressures will not have a material adverse effect on OPG's business, operating results, financial position or prospects. See *"Background – Ontario's New Electricity Market"*.

Market Power Mitigation/Decontrol

OPG is subject to certain market power mitigation targets relating to decontrol of generation capacity in Ontario. The fulfilment of these targets will fundamentally change OPG's competitive position in Ontario. Completion of decontrol initiatives within the mandated time frame is also subject to governmental and regulatory approvals which may affect the economics of a proposed transaction and, ultimately, OPG's ability to decontrol generation assets on favourable terms or at all. To date, OPG has leased its Bruce A and B nuclear generating stations to Bruce Power on a long term basis in a transaction which closed in May 2001 and has sold its Mississagi hydroelectric generation stations to Mississagi Power Trust in a transaction which closed in May 2002. Due to factors including difficult market conditions, it may take somewhat longer than first anticipated to finish the balance of OPG's announced decontrol initiatives involving the Lakeview, Lennox, Atikokan and Thunder Bay fossil generating facilities. The failure of OPG to obtain satisfactory terms in decontrol transactions could have an adverse effect on OPG's business, operating results, financial condition or prospects, including if the OEB does not confirm that a transaction qualifies as a "decontrol" transaction. In addition, the extent to which OPG will be able to retain the proceeds from such transactions is uncertain. The OEB has not yet decided whether the Bruce Power and Mississagi transactions will qualify as decontrol transactions. OPG filed for OEB approval for both the Bruce and Mississagi transactions late in 2002 and a decision is expected around the end of the first quarter of 2003. Although OPG believes that these transactions will satisfy its decontrol obligations, there can be no assurance that the OEB will come to that determination. The Bruce Power and Mississagi hydroelectric transactions are not conditional on and it is expected that future transactions will also not be conditional on OEB approval and therefore cannot be unwound even if they are determined by the OEB not to constitute decontrol transactions. Accordingly, it is possible that OPG may be required to dispose of additional production assets in order to satisfy its 42 month and 10-year market power mitigation targets under its generation licence. See *"Background – Ontario's New Electricity Market – Market Power Mitigation"*.

OPG's revenue will be affected by the rebate mechanism that will apply to a significant amount of electricity until the completion of OPG's mandated decontrol of generation capacity, unless terminated earlier by the OEB. OPG will have to pay a rebate to the IMO if the average spot market price as calculated under the framework exceeds 3.8 cents per kWh for the predetermined amount of electricity. This predetermined amount of electricity has been established up until 2004 and there is no assurance as to the amount that will be applicable to OPG thereafter. The IMO will pass on this rebate to all Ontario electricity consumers. Accordingly, OPG's ability to maximize its revenue will be affected by the rebate mechanism. In the event that the OEB were to determine that the Bruce Transaction does not qualify as transfer of effective control of the output of the Bruce nuclear facility generating units, this would leave OPG with the Market Power Mitigation Framework rebate obligation but not the spot market revenues associated with Bruce generation. In the longer term, a negative outcome on meeting the decontrol test could require OPG to decontrol an additional 3,160 MW of production assets in order to meet the 10-year market power mitigation targets and, if it does not, it may have an adverse effect on OPG is business, operating results, final condition or prospects. See *"Business of OPG – Regulation – Ontario's Electricity Industry – Market Power Mitigation – Rebate Mechanism and Price Relief"*.

There can be no assurance that OPG will not be subject to additional or different market power mitigation obligations in the future which could materially adversely affect OPG's business, operating results, financial condition or prospects. See *"– Restructuring of Ontario's Electricity Industry"*.

Nuclear Operations

OPG developed its current nuclear recovery plan in 1997 with a group of independent nuclear experts. Its successful implementation will depend on many factors, including: no unanticipated deficiencies in its nuclear operations or greater-than-anticipated deterioration to its nuclear generating assets; no material changes to the current regulatory structure governing nuclear generation; the ability of OPG to hire, train and retain senior management and other qualified personnel; the ability of OPG to increase productivity; the ability of OPG to implement management and operational changes and the sufficiency of the allocated funds for implementing the

nuclear recovery plan. OPG had implemented various recovery initiatives in the 1990s which did not significantly improve its nuclear performance. These initiatives did not adequately identify the underlying causes of OPG's declining nuclear performance and generally lacked sufficient levels of planning, co-ordination, resources and accountability.

There can be no assurance that OPG will be able to fully implement its nuclear recovery plan and even if implemented, that improvements to OPG's nuclear operating performance will be significant and sustainable. In the event that OPG does not fully realize the intended benefits of implementing its current nuclear recovery plan, electricity production from OPG's nuclear facilities may be lower than anticipated; operating costs may be higher than expected; and additional regulatory requirements or constraints could be imposed. Any one of these results could have a material adverse effect on OPG's business, operating results, financial condition or prospects. See *"Business of OPG – Generation Operations – Nuclear Operations – Generating Facilities – Pickering A Lay-Up and Restart"*.

The staged restart of the four units at OPG's Pickering A nuclear station is a key corporate initiative and is expected to enhance OPG's competitive position. In February 2001, the CNSC released its decision with respect to an environmental assessment under the *Canadian Environmental Assessment Act*, which allowed the CNSC to proceed with consideration of OPG's licence application through the normal public hearing process under the NSC Act. Subsequently, OPG's licence application for the re-start of Pickering A was approved by the CNSC on November 5, 2001. The amended licence permits OPG to return the four Pickering A reactors to service, subject to the completion of specified improvements and upgrades. The amended licence is valid until June 30, 2003, (unless suspended, amended, revoked or replaced) and may be renewed. OPG is currently in the process of seeking a renewal of the Pickering A licence for a further two-year term. To the extent there are significant delays in the project or increases in costs, this could materially adversely affect OPG's business, operating results, financial condition or prospects. See *"Business of OPG – Risk Factors – Nuclear Operations – Pickering A Lay-Up and Restart"*. In addition, the Province has announced it intends to set up an independent investigation into delays in and the cost of restarting the Pickering A station.

OPG has comprehensive inspection and testing programs in place in order to ascertain the physical condition of its nuclear generating stations. In particular, it has undertaken an ongoing program to assess the condition of its steam generators, fuel channels and related infrastructure such as feeder pipes as part of its nuclear recovery plan. As a result of these programs, OPG has identified equipment life-cycle issues, such as steam generation tube corrosion, feeder pipe wall thinning and pressure tube/calandria tube contact. These conditions were generally anticipated in the design but experience has shown that the rate of degradation is higher than anticipated. The associated life cycle plans for these components are intended to monitor and mitigate the degradation. In addition, as no nuclear generating station utilizing CANDU technology has yet completed a full life cycle, there is a risk that there could be unforeseen technological or equipment issues that are materially adverse to the business, operating results, financial condition or prospects of OPG. Accordingly, there can be no assurance that OPG will not have to incur significant expenditures for repairs or replacements in addition to those contemplated under its nuclear recovery plan. To address these issues, OPG may need to increase preventative maintenance programs and allow for more outage time than currently is planned. Such repairs or replacements could have a material adverse effect on OPG's business, operating results, financial condition or prospects. OPG's success will depend, in part, on its ability to maintain an economically efficient portfolio of nuclear generation assets. See *"Business of OPG – Generation Operations – Nuclear Operations – Generating Facilities"*.

One CANDU nuclear reactor outside of Ontario has recently experienced feeder pipe cracking. OPG has not experienced any feeder pipe cracking at any of its nuclear facilities, but it continues to closely monitor this issue.

OPG is subject to extensive federal regulation with respect to its nuclear operations. Risks of substantial liability, as well as the potential for significant increased costs of operations, arise from the ownership and operation of nuclear generating stations, including, among other things, structural problems, increasing security requirements to cover factors such as physical security threats, equipment malfunctions, the storage, handling and disposal of radioactive materials and uncertainties with respect to the technological and compliance costs associated with nuclear waste management and decommissioning. An increase in any of these costs may have a material adverse effect on OPG's business, operating results, financial condition or prospects. OPG has implemented risk management strategies such as the reactor physics strategy with respect to changed requirements of the CNSC with

respect to reactor physics codes (see *"Generation Operations – Nuclear Operations – Reactor Physics"*), but there can be no assurance that such risks can be minimized.

A major accident at a nuclear installation anywhere in the world could impact the regulation of OPG's activities or the future prospects for nuclear generation. See *"Business of OPG – Regulation – Nuclear Regulation and – Generation Operations – Nuclear Operations"*.

OPG is also subject to Federal regulation of its nuclear waste management practices. Management of nuclear waste poses unique risks. Failure to comply with the applicable requirements could have a material adverse impact on OPG. In addition, changes in federal regulation could result in costs in addition to the substantial costs currently incurred by OPG for nuclear waste management which could have a material adverse effect on OPG's business, operating results, financial condition or prospects. See *"Business of OPG – Regulation – Nuclear Regulation"*.

Although the Federal Government has recently enacted Bill C-27, the *Nuclear Fuel Waste Act*, there is no facility for the permanent disposal of nuclear waste currently in operation in Canada, nor has the CNSC licensed any such facility. OPG's nuclear waste management and decommissioning obligations are subject to numerous factors, including: assumptions regarding implementation schedules, cost estimates, discount rates and the rate of return earned on segregated funds established to satisfy these obligations; the tax-deductibility of OPG's contributions paid to the segregated funds should OPG's tax-exempt status change; the tax-exempt status of income earned on the segregated funds; the sale tax treatment of expenditures incurred by the Nuclear Waste Management Organization; changes in Federal policy or regulation regarding nuclear waste management and decommissioning (including, but not limited to, financial assurance requirements, program standards, the method of and future availability of long-term waste management and other assumptions under OPG's nuclear waste management and decommissioning programs); and the degree of control OPG will have over the scope and implementation of its programs. Many of these factors relate to matters which are untested or for which there is no significant degree of certainty. Changes in any of these factors could materially adversely affect OPG's business, operating results, financial condition or prospects. See *"Business of OPG -Generation Operations - Nuclear Operations – Nuclear Waste Management and Decommissioning"*.

OPG and the Province have entered into the Ontario Nuclear Funds Agreement, under which the Province limits OPG's financial exposure in relation to certain used fuel management costs. This agreement is to become effective as of April 1, 1999, once the supplementary agreements for the custodianship and management of the funds are entered into with the Province, expected in 2003. Under the principles of this agreement, OPG would continue to be responsible for significant nuclear waste management liabilities. If those costs exceed current estimates, OPG's liability for nuclear waste management can increase significantly but its liability for the long-term storage and disposal of nuclear used fuel waste will effectively be capped. The Province does not limit OPG's financial exposure to decommissioning and low and intermediate level waste management costs; accordingly, OPG will be liable to make up any deficiency in the funding of these costs. OPG is also fully responsible for all incremental costs relating to the management of used fuel bundles in excess of 2.23 million bundles. Northern community opposition to geologic disposal of used fuel and potential station community opposition to prolonged on site used fuel storage may impede the ability of the Nuclear Waste Management Organization to develop plans acceptable to major stakeholders. In addition, community support for centralized storage of low and intermediate level waste at the Western Waste Management Facility at the Bruce site may erode due to reduced OPG presence at the site and concerns for low level emissions. Consultation programs and studies based on international practices and standards have been undertaken to address these concerns. See *"Business of OPG – Generation Operations – Nuclear Operations – Nuclear Waste Management and Decommissioning"* and *"– Ownership by the Province; Potential Conflicts of Interest with the Province and Related Parties"*.

The level of OPG's contributions to the segregated funds established under the Ontario Nuclear Funds Agreement will be impacted, potentially materially, by any changes to decommissioning and waste management reference plans and associated cost estimates, the tax treatment of the funds and contributions to the funds and the requirements of the Ontario Nuclear Funds Agreement and the *Nuclear Fuel Waste Act*.

OPG's contributions to the segregated funds are deductible under the proxy tax regime currently applicable to the Corporation and certain of its Canadian subsidiaries. In addition, any related investment income earned on these funds is treated by OPG as being exempt from proxy tax. The trust fund for the long term management of

used fuel, governed by the *Nuclear Fuel Waste Act*, may be subject to taxation under the *Income Tax Act* (Canada) on some or all of its investment income. However, the Federal Government has indicated to the provinces of Ontario, Quebec and New Brunswick that it will take appropriate measures to ensure that such income is exempt from tax provided certain conditions are met – see *"Business of OPG – Relationship with the Province and Others – Taxation of Provisions for Future Nuclear-Related Costs*. This is no assurance that this will in fact occur. The other segregated funds to be established by OPG under the Ontario Nuclear Funds Agreement will be custodial funds. These funds are not taxed as a separate entity under the *Income Tax Act* (Canada). Since the Corporation owns these funds, any related investment income earned will be attributed to the Corporation and accordingly such income will be exempt from taxation under the *Income Tax Act* (Canada) because the Corporation is exempt from tax under this Act. If OPG loses its tax-exempt status, there can be no assurance that the fund contributions would continue to be deductible in determining the tax liability of the Corporation or its subsidiaries, nor that the investment income earned on these funds would continue to be tax-exempt – see *"Business of OPG – Relationship with the Province, Stranded Debt, Proxy Taxes and Effect of Change in Ownership on Tax Status"*. If these contributions were not deductible in determining OPG's tax liability, OPG's annual tax liability would increase materially by approximately $140 million per year for the period 2002 to 2008, based on an average of the applicable tax rates. If the investment income were also taxable, the contributions would increase from $454 million annually to approximately $800 million annually for the years 2002 to 2008. If the estimated cost of nuclear waste management and decommissioning increases beyond current estimates, OPG's liability and these contributions would increase further. In addition, if the NWMO is unable to receive the same sales tax treatment that the Corporation would be entitled to receive if this organization had not been established, OPG's liability and these contributions would increase even more – see " *Business of OPG – Relationship with the Province and Others – Taxation of Provisions for Future Nuclear – Related Costs*". While the outcome cannot at this stage be determined, the Corporation has been engaged in discussions with the relevant taxation authorities to review various alternative structures or arrangements to negate these potential negative tax results.

Although reserves of natural uranium are relatively abundant, the market price and available supply of uranium concentrates may be volatile from time to time. OPG currently uses one contractor to convert its uranium concentrates into uranium dioxide and one independent manufacturer to process uranium dioxide into finished nuclear fuel bundles. These advanced stages of the nuclear fuel supply chain are more susceptible to supply security, price and quality risks. OPG has entered into various contractual arrangements to mitigate these risks, but these risks cannot be entirely eliminated. Failure by OPG to obtain adequate supplies of nuclear fuel of satisfactory quality and price could have a material adverse effect on OPG's business, operating results, financial position or prospects. See "*Business of OPG – Generation Operations – Nuclear Operations – Nuclear Fuel Procurement*".

Human Resources and Labour Relations

OPG's ability to implement its corporate strategy is dependent upon its success in attracting and retaining senior management and other personnel and the ability of management and personnel to work together as a cohesive team capable of operating in a competitive environment. OPG must acquire and retain personnel with the skills required to implement new processes and systems and to develop new lines of business. Skilled managers and other employees are also required to ensure that project management and control objectives are satisfied in connection with major corporate initiatives such as the Pickering A restart, the selective catalytic reduction installations at OPG's Lambton and Nanticoke stations and the planned maintenance programs at the nuclear stations. OPG must also develop training programs and succession plans to ensure that its operational staffing needs are met in the future, as the demographics of OPG's workforce poses a significant challenge with approximately 24% of OPG's personnel eligible for retirement by 2007. In some parts of the organization, the risk is much higher. Many of OPG's employees possess experience and skills that will be highly sought-after by competitors in the open market. There can be no assurance that OPG will be able to attract and retain qualified personnel. This risk increased with corporate restructuring that will see a reduction of approximately 1,700 employees by the end of 2004.

The majority of OPG's employees are represented by either the PWU or The Society. The tenor of negotiations with both unions has varied with the economic climate in Ontario, ranging from challenging and difficult to conciliatory and collaborative. This has resulted in complex collective agreements that, historically, have placed constraints on management's traditional flexibility to operate its business in a cost-efficient manner. In addition, in implementing decontrol transactions, OPG will need to maintain core capabilities in essential areas and to maintain service levels during transition periods, while seeking to achieve optimum staffing allocations. To achieve these objectives, OPG has negotiated collective agreements with its two major unions which OPG believes

will facilitate restructuring activities as it positions itself for the competitive market and aligns the design and size of its support organizations with staffing requirements following decontrol transactions. During the 2001 negotiations with the PWU major changes were made to the wage structures and work assignment portions of the collective agreement. The concept of skill broadening was introduced. Skill broadening allows employees to work outside of their traditional roles by performing a wider range of duties. This is expected to improve productivity and employee job satisfaction. Employees were also placed into three pay bands and the number of job documents was reduced from over 1,000 to approximately 100. In addition, a large number of penalty payments were reduced. These changes will simplify the pay and administrative processes. See *"Business of OPG – Human Resources"*.

Ownership by the Province; Potential Conflicts of Interest with the Province and Related Parties

The Province owns all of the Corporation's issued and outstanding common shares. Accordingly, the Province has the power to determine the composition of the Corporation's Board of Directors. The Corporation and the Province have a shareholder's agreement that addresses such issues as OPG's provision to the Province of the information necessary to allow the Province to periodically inform Ontario's legislature regarding matters such as: OPG's ongoing performance, compliance with market power mitigation, information in respect of matters requiring shareholder approval and appropriate financial reports. In addition, the shareholder's agreement addresses OPG's governance relationship with the Province with respect to certain actions. These include any proposal to issue or transfer shares in the Corporation or any of its subsidiaries, the preparation of long-term business plans, matters concerning dividend policy and the entering into of any major transaction by the Corporation or any of its subsidiaries which would potentially have a material effect on the financial interest of the Province or OPG's ability to make proxy tax payments. The shareholder's agreement also precludes the release by the Province of non-public, commercially sensitive information regarding OPG.

The declaration and payment of dividends are at the sole discretion of the Corporation's Board of Directors and will be dependent upon the Corporation's results of operations, financial condition, cash requirements and other factors considered relevant by the Corporation's Board of Directors.

Conflicts of interest may arise between OPG and the Province as a result of the obligation of the Province to act in the best interests of its residents in a broad range of matters, including the regulation of Ontario's electricity industry, the regulation of environmental matters, the allocation between OPG and the Province of the costs involved in nuclear waste management, the reduction of the stranded debt from the revenues of the electricity industry and any future sale by the Province of all or any of the Corporation's assets or common shares and the determination of the amount of payments to be made by the Corporation to the Province by way of dividends. For example, in 2002 the Province enacted the *Electricity Pricing, Conservation and Supply Act, 2002*. See – *"Ontario's Electricity Market – Recent Changes to Ontario's Electricity Market"*.

The Province has the power to alter the proxy tax, the gross revenue charge or other taxes or similar charges imposed on OPG.

In addition, as described under *"Business of OPG – Relationship with the Province and Others – Stranded Debt, Proxy Taxes and Effect of Change in Ownership on Tax Status – Effect of Change in Ownership on Tax Status"*, the Corporation will be required to pay proxy tax (the "Exit Tax") on any income deemed to have been realized upon the deemed disposition of its assets upon losing its tax-exempt status. The amount of Exit Tax that will be payable by the Corporation should it ever lose its tax-exempt status cannot be definitively estimated at this time, but could well be material.

Under the current taxation regime, the Corporation and its subsidiaries could incur material tax liabilities, or lose the right to deduct certain material amounts in respect of contributions to the segregated funds established in respect of nuclear waste management and decommissioning liabilities in calculating income subject to proxy tax or income tax, as the case may be, if the Province's equity interest were to fall below the 90% threshold. See *"Business of OPG – Relationship with the Province and Others – Stranded Debt, Proxy Taxes and Effect of Change in Ownership on Tax Status – Effect of Change in Ownership on Tax Status"*.

Under the Ontario Nuclear Funds Agreement, any changes to OPG's reference plans or cost estimates for nuclear waste management and decommissioning, other than changes required by a regulatory authority, require the approval of the Province, acting reasonably. There can be no assurance as to the terms on which any such approval

might be granted or that the Province will accept any reference plan cost estimates that result in a reduction in payments under the Ontario Nuclear Funds Agreement.

Environmental Risks

OPG is subject to Federal, Provincial and Municipal environmental regulation. Failure to comply with such laws can subject OPG to significant liabilities, including fines and other penalties. The release of certain substances on or from properties owned, leased, occupied or used by OPG or as a result of OPG's operations has resulted and could further result, in governmental orders requiring the investigation, control and/or remediation of such releases. The presence or release of such substances could have a material adverse effect on OPG's ability to sell its interest in such property or could lead to claims by third parties as a result of the release of such substances.

OPG incurs substantial capital and operating costs to comply with environmental laws and its voluntary environmental programs. The regulatory requirements relate to discharges to the environment; the handling, use, storage, transportation, disposal and clean-up of hazardous materials, including both hazardous and non-hazardous wastes; and the dismantling, abandoning and restoration of generation facilities at the end of their useful lives. See "*Business of OPG – Regulation – Environmental Regulation*".

Any changes in applicable environmental laws, or their enforcement, may impose material additional costs on OPG and could materially impact the value of certain of OPG's assets. These could include, for example, possible changes to regulations relating to air emissions of SO_2, NO_x, CO_2, mercury and particulates, as well as the accelerated phase-out of PCBs. In addition, new approvals or permits or renewals of existing approvals and permits may require environmental assessment and/or result in the imposition of conditions which may be costly. The process for obtaining environmental permits and approvals, including any necessary environmental assessment, can be lengthy, controversial and expensive. OPG could experience difficulty and significantly increased costs to meet new environmental regulation in Ontario, to obtain permits or approvals or to comply with the conditions of new or revised permits or approvals. Such developments could have an adverse effect on OPG's business, operating results, financial condition or prospects.

In recent years, OPG has relied increasingly on fossil generation to compensate for declining nuclear generation and, starting in 1998, to replace nuclear generation that has been taken out of service as a result of the lay-up of the Pickering A. OPG's inability to restore nuclear generation would require it to continue to rely upon its current high level of fossil generation.

The amount of electricity that OPG may produce at its fossil generating stations is constrained, in part, by Provincial, Federal international and voluntary acid gas and other emission limits. OPG's ability to sustain or increase fossil generation relative to current levels will depend, in part, on the operation of an effective emission reduction credit trading regime in Ontario. The imposition of further, more stringent, air emission limits or changes to the emissions trading regime could have a material adverse effect on OPG's business, operating results or financial condition. See "*Business of OPG – Fossil Operations – Effective Generation Limits and Air Emissions*".

Reliance Upon Transmission Systems

OPG depends on the capacity and reliability of the transmission and interconnection systems that connect its generators with customers in Ontario and in the export markets. In Ontario, the capacity of such transmission systems is limited under certain conditions and OEB approval is required for its expansion. An element of OPG's strategy is to increase its export of electricity to the U.S. northeastern and midwestern markets. OPG may also face transmission constraints in its target export markets. The capacity and operating reliability of such interconnection, transmission and distribution systems are factors beyond OPG's control and any capacity limitations, restrictions on access or reductions in operating reliability could have an adverse effect on OPG's business, operating results, financial condition or prospects. See "*Business of OPG – Relationship with the Province and Others – Relationships with Ontario Hydro's Successors*", "*Business of OPG – Markets and Customers – OPG's Markets – Interconnected Markets*" and "*– Interconnected Markets*".

Interconnected Markets

OPG's ability to penetrate interconnected markets depends upon many external factors, including: the cost to transmit electricity to these markets; the price of electricity in these markets; the competitive actions of other

generators and power marketers; the pace of deregulation in Ontario and pace and nature of deregulation in the interconnected markets; currency exchange rates; any new trade limitations; OPG retaining a FERC licence; and costs to comply with environmental standards imposed in these markets. There can be no assurance that OPG will continue to compete successfully in the U.S. interconnected markets. OPG's inability to access or compete in these markets could have a material adverse effect on OPG's business, operating results, financial condition or prospects, particularly in the context of market power mitigation. See *"Business of OPG – Markets and Customers – OPG's Markets – Interconnected Markets"* and *"Business of OPG – Regulation – Energy Regulation"*.

Fossil Fuel Supply

OPG's coal and gas/oil-fired electricity production is dependent on a secure, reasonably priced supply of coal, natural gas and oil. A number of factors, including mine production problems, rail transportation problems and shipping schedule disruptions could lead to temporary shortages in the supply of coal or increases in the price of coal. These factors could have a materially adverse impact on OPG. Similarly, gas and oil prices and availability can also be affected by numerous factors. Given the fuel mix of OPG's current fleet, the potential impact of gas/oil supply disruptions on OPG is much smaller than the potential impact of coal supply disruptions.

OPG manages fossil fuel supply issues through its contracting strategy, the use of a diversity of sources and through inventory management. Similarly, gas/oil prices and availability risks are managed through a mixture of spot purchases and long-term contracts and the ability to convert floating price contracts into fixed price contracts in a rising market. A reduction of OPG's coal-fired production due to supply issues could have a material adverse effect on OPG.

Hydroelectric Generation

Approximately 48% of OPG's in-service hydroelectric capacity depends on water rights derived from treaties between Canada and the United States which are terminable upon 12 months' notice. Although OPG does not expect that Canada or the United States will exercise their termination rights under those treaties in the foreseeable future, there can be no assurance that such termination will not occur. The loss of the ability to generate power at some or all of its facilities could have a material adverse effect on OPG's business, operating results, financial condition or prospects. See "*Business of OPG – Regulation – Water Rights*".

OPG pays gross revenue charges to the Province and makes water rental payments to other jurisdictions. Significant increases in gross revenue charges post-2003 and water rentals could have a material adverse effect on OPG's business, operating results, financial condition or prospects. See "*Business of OPG – Relationship with the Province and Others – Stranded Debt, Proxy Taxes and Effect of Change in Ownership on Tax Status*".

The occurrence of dam failures at any of OPG's hydroelectric generating stations could result in significant liability for damages and a loss of generating capacity and repairing such failures could require OPG to incur significant expenditures of capital and other resources. OPG implemented a dam safety program in 1986 to minimize the risks associated with dam failures. The program consists of inspections, assessments and monitoring to detect potential failures and remediate high risk conditions and emergency response plans to minimize the consequences of dam failure. There can be no assurance that the dam safety program will be able to detect potential dam failures prior to occurrence or eliminate all adverse consequences in the event of a failure. Upgrading all dams to enable them to withstand all low probability events could require OPG to incur significant expenditures of capital and other resources. The consequences of dam failures could have a material adverse effect on OPG's business, operating results, financial condition or prospects.

Effects of Weather

By the nature of its business, OPG's earnings are sensitive to weather variations from period to period. Variations in winter weather affect the demand for electrical heating requirements. Variations in summer weather affect the demand for electrical cooling requirements. Variations in precipitation also affect water supplies, which in turn, affect OPG's generating capacity by limiting OPG's ability to utilize its low-cost hydroelectric generating assets. This may result in increased reliance on other sources of generation.

Effects of Ontario Economy

An economic slowdown in Ontario would negatively impact OPG's earnings. During the period beginning in the 1950s and ending in the 1980s, the annual growth rate of electricity demand in Ontario declined from approximately 8% to approximately 3% on a weather-normalized basis, a pattern which was typical across North America. In the early 1990s, consumption in Ontario declined both as a result of the recession and due to the substantial electricity price increases in Ontario which were required, in large part, to recover capital costs associated with construction of the Darlington nuclear generating station. Price increases for electricity also precipitated substantial fuel switching from electricity to natural gas. Between 1994 and 2000 overall electricity demand grew at an annual rate of about 1.6% on a weather normalized basis, but in 2001 it remained flat as a result of slow economic growth. OPG expects Ontario primary demand to grow at an average annual rate of 1.4% between 2001 and 2010.

Government Regulation

OPG's operations are subject to government regulation that may change from time to time. Matters that are subject to regulation include: structure of the electricity market, nuclear operations (including regulation pursuant to *Nuclear Safety and Control Act* (Canada), the *Nuclear Liability Act* (Canada) and the *Emergency Plans Act* (Ontario), nuclear waste management and decommissioning, water rentals, environmental matters including air emissions and proxy tax payments. Operations that are not currently regulated may become subject to regulation. Because legal requirements can be subject to change and are subject to interpretation, OPG is unable to predict the impact of such changes on OPG and its operations. See *"Business of OPG – Regulation"*.

Liquidity Risk

OPG operates in a capital-intensive business. Significant financial resources are required to return the Pickering A station to service and to fund other improvement projects and potential expenditures necessary to comply with air emission or other regulatory requirements. As well, funds are required for payments under the restructuring initiative, the market power mitigation agreement rebate, contributions under the Ontario Nuclear Funds Agreement and other obligations including funding of OPG's pension fund commencing in 2003.

OPG has liquidity requirements over the next 18 months which exceed its current banking facilities. In order to meet these liquidity requirements, OPG must successfully access the mid-term note market under its shelf program, as well as defer certain debt maturities and other obligations to the Province.

OPG's ability to arrange debt financing is dependent on a number of factors including: general economic and capital market conditions; credit availability from banks and other financial institutions; maintenance of acceptable credit ratings; and the status of electricity market restructuring in Ontario.

OPG's liquidity is highly dependent on its debt rating and the mark-to-market value of contracts with counterparties. A change in the rating could result in additional collateral requirements with counterparties, depending on the mark-to-market value of the contracts. In particular, where counterparties are in a positive mark-to-market position and OPG is in a negative position, a downgrade of OPG's long-term debt ratings could trigger increased collateral requirements based on the provisions of the contracts.

OPG believes cash flows from operations, available short-term committed credit facilities and the successful issuance of debt in the capital markets should provide adequate liquidity for OPG's on-going requirements.

Financing Requirements

All of OPG's debt is currently held by the OEFC. As at December 31, 2002, the debt owing to the OEFC consists of $2,450 million aggregate principal amount of senior notes and $750 million aggregate principal amount of subordinated notes. These amounts mature over the 2005 to 2011 period.

The Company has reached agreement with OEFC to extend the maturity date of the $700 million principal amount of the notes previously due in 2003 and 2004 by two years, with the interest rate remaining unchanged. The debt maturities due in the next five years are as follows: 2003: $0; 2004: $0; 2005: $500 million; 2006: $800

million; and 2007: 400 million. See Note 6 to the Corporation's audited consolidated financial statements for the year ended December 31, 2002, which reflects debt maturity dates.

The Province does not guarantee the Corporation's current indebtedness. OPG expects that cash from its operations, together with additional borrowings available to OPG under existing credit facilities along with the potential for a new public debt facility, should provide sufficient financial resources during 2003 and 2004 to satisfy its forecast capital and other expenditures.

The Corporation is planning to issue its first public debt during 2003. The success of a new public debt offering will be dependent on the Corporation's ability to access the capital markets. The Corporation's ability to arrange sufficient debt financing on satisfactory terms could be affected by numerous factors, including: its results of operations and financial condition; conditions in the capital and bank credit markets; the ratings assigned to the Corporation's debt securities; the regulatory environment in Ontario; general economic conditions; investor confidence in the Ontario electricity industry and the Corporation; investor concerns following a major accident at a nuclear installation anywhere in the world; the success of OPG's nuclear recovery plan; OPG's relationship with its sole shareholder, the Province; and the status of the electricity market in Ontario. The failure or inability on the part of the Corporation to access debt markets on satisfactory terms could have a material adverse effect on the Corporation's business, operating results, financial condition or prospects. See "*Business of OPG – Regulation*".

OPG's cash flow could be negatively affected by lower generation capacity upon the implementation of decontrol initiatives in furtherance of OPG's market power mitigation obligations and continuing expenditures relating to the Pickering A return to service project. Revenues from production of the Pickering A units, of which OPG expects to have the first unit in-service by the summer of 2003, are expected to partially offset these reductions in cash flow in 2003. However, there can be no assurance that OPG will not require additional financing to supplement cash from operations in order to provide sufficient financial resources to satisfy its funding requirements to meet forecast capital and other expenditures.

Credit ratings are intended to provide investors with an independent measure of the credit quality of an issue of securities. At December 31, 2002, OPG was rated BBB+ (negative outlook) by S&P and A (low) by DBRS. Maintaining an investment-grade credit rating is essential for corporate liquidity, capital market access and to facilitate energy and financial product sales and trading activities.

Credit Risk

Credit risk is the financial risk of non-performance by contractual counterparties. Subsequent to market opening, the majority of OPG's revenues are derived from sales through the IMO-administered spot market. OPG also derives revenue from several other sources including the sale of financial risk management products to third parties.

OPG actively manages its credit risk exposures through the enforcement of an established counterparty credit policy. OPG manages counterparty credit risk through dealing with investment grade counterparties, monitoring and limiting its exposure to counterparties with lower credit ratings, active collateral management and by avoiding excessive concentration with any one counterparty or category of counterparties. Credit exposures include both settlement and market-based components. OPG's credit exposure is concentrated in the physical market with the IMO.

Since the Ontario market opened in May 2002, credit exposure to the IMO has fluctuated based on timing and peaked at $1.2 billion. OPG's management believes that this is an acceptable risk due to the IMO's primary role in the Ontario market. The IMO manages its own credit risk and its ability to pay generators by mandating that all registered IMO spot market participants meet specific IMO standards for creditworthiness and collateralization. OPG also measures its credit concentrations with counterparties in the financial instrument market. OPG management believes these are within acceptable limits and does not anticipate any material effect on its results of operations or cash flows arising from potential defaults.

The following table provides information on credit risk from energy sales and trading activities as at December 31, 2002.

(millions of dollars)			
Credit Rating [1]	Potential Exposure [2]	Number of Counterparties	Potential Exposure For 10 Largest Counterparty Exposures[2]
AAA to AA	31	10	17
A+ to A-	210	46	128
BBB+ to BBB-	118	72	29
BB+ to BB-	55	30	0
B+ to B-	18	10	9
Total	432	168	183
IMO	601	1	601
Total	1,033	169	784

Notes:

[1] Credit ratings are based on OPG's own analysis, taking into consideration external rating agency analysis where available, as well as recognizing explicit credit support provided through guarantees and letters of credit or other security.

[2] Potential exposure represents OPG's assessment of the maximum exposure of the 10 largest counterparties for OPG as a whole, over the life of each transaction at 95% confidence.

Foreign Exchange and Interest Rate Risk

OPG's foreign exchange risk exposure is attributable primarily to U.S. dollar-denominated transactions such as the purchase of fuel. OPG currently manages its exposure by periodically hedging portions of its anticipated U.S. dollar cash flows according to approved risk management policies.

OPG has interest rate exposure on its short-term borrowings and investment programs. The majority of OPG's debt is fixed on a long-term basis. Interest rate risk arises with the need to undertake new financing and with the potential addition of variable rate debt. Interest rate risk may be hedged using derivative instruments. The management of these risks is undertaken by selectively hedging in accordance with corporate risk management policies.

Commercial Risks

OPG's portfolio of generation assets and electricity trading and marketing operations are subject to inherent risks, including financial, operational, regulatory and strategic risks. To manage these risks, OPG has implemented an enterprise-wide risk management framework which includes governance policies, organizational structures and risk measurement and monitoring processes.

OPG's Board of Directors is ultimately responsible for managing the risks inherent in OPG's business. It regularly monitors OPG's risk exposures and has approved the overriding governance policies, structures and limits for management of OPG's risks. A Risk Oversight Committee, which consists of senior officers and executives of OPG, has been established by the Chief Executive Officer to approve markets and products, monitor policies and compliance issues and ensure the continuing effectiveness of overall corporate governance under the direction of the Board of Directors. Coordination of corporate-wide risk management activities occurs through a centralized corporate risk office. A well defined separation and independence exists between the corporate risk office and operational management.

OPG maintains a comprehensive trade capture and risk management system with related processes and controls. OPG's commercial activities are separated into portfolios to capture the risks inherent in each transaction for each portfolio. This process facilitates the effective identification and measurement of risks and the application of appropriate position and risk limits for performance and risk management purposes. The methodology used to measure these risks includes the use of consistent and recognized risk measures for monitoring trading activities and the generation portfolio. See *"Business of OPG – Risk Factors"*.

Commodity Price Risk

Commodity price risk is the risk that changes in the market price of electricity or fossil fuels will adversely impact OPG's earnings and cash flow from operations. OPG faces commodity price risk directly related to both the demand and supply of generation in the open market and transmission constraints. OPG's electricity production and a portion of OPG's fossil fuel requirements are exposed to spot market prices. To manage this risk, OPG maintains a balance between the commodity price risk inherent in its electricity production and plant fuel portfolios.

In addition to fixed price contracts for fossil and nuclear fuels, OPG employs derivative instruments to hedge its commodity price risk. The production from OPG's hydroelectric facilities is also a natural hedge of fuel price risk.

The percentage of OPG's generation and fuel requirements hedged over the next three years is shown below:

	2003	2004	2005
Estimated generation output hedged [1]	80%	81%	75%
Estimated fuel requirements hedged [2]	84%	85%	77%

Notes:

(1) Represents the portion of megawatt-hours of future generation production for which OPG has sales commitments and volumes related to the market power mitigation rebate and transition rate option contracts.

(2) Represents the portion of estimated future fuel requirements (based on MMBTU equivalents) for which OPG has entered contractual arrangements to manage related procurement price risks.

Open trading positions are subject to measurement against value-at-risk ("VaR") limits, which measure the potential change in the portfolio's market value due to price volatility over a one-day holding period, with a 95% confidence interval. OPG's approved VaR limit is $5 million. The VaR limits ranged between $0.7 million to $1.9 million during 2002.

Generation Risk

OPG is exposed to the market impacts of uncertain output from its generating units or generation risk. The amount of electricity generated by OPG is affected by such risks as fuel supply, equipment malfunction, maintenance requirements and regulatory and environmental constraints. To mitigate earnings volatility due to generation risk, OPG enters into multiple short-term and long-term fuel supply agreements and long-term water use agreements, manages fuel supply inventories and follows industry practices for maintenance and outage scheduling. In addition, OPG ensures regulatory requirements are met, particularly with respect to licensing of its nuclear facilities and manages environmental constraints utilizing programs such as emission reduction credits.

OPG maintains general public liability, property and business interruption insurance, subject to deductibles. The occurrence of a significant event that is not fully insured or indemnified against, or the failure of a party to meet its indemnification obligations, could materially and adversely affect OPG's consolidated results of operations and financial position. See *"Business of OPG – Generation Operations"*.

Pension Plan

OPG operates a contributory defined benefit pension plan. The OPG pension plan is funded in accordance with the *Pension Benefits Act* (Ontario) and the *Income Tax Act* (Canada). In keeping with this legislation, the current funding requirements of the plan are set out in the most recent funding valuation report filed with the appropriate regulatory authorities. The actuarial funding report filed with the Financial Services Commission of Ontario dated as of April 1, 2002, indicates the pension plan had a surplus of over $262 million. OPG estimates contributions will be required to be made to the pension fund by the fourth quarter of 2003 and all of 2004. OPG will be required to contribute the current pension service cost of approximately $160 million per year. The next actuarial valuation must occur no later than April 2005.

Forward-Looking Information

This annual information form includes forward-looking statements and information. Words such as "may", "will", "expect", "anticipate", "believe", "estimate", "plan", "intend" and similar expressions have been used in this annual information form to identify forward-looking statements. These forward-looking statements have been based on estimates and assumptions made by OPG's management. Although OPG believes that these estimates and assumptions are reasonable, actual results could differ materially from those projected in the forward-looking statements. Forward-looking statements are not guarantees of future performance or results and are subject to various factors, including the risk factors contained herein. OPG is not obligated to update or revise any forward-looking statements, whether as a result of new information, future events or otherwise. Because of these risks, uncertainties and assumptions, undue reliance should not be placed on these forward-looking statements.

ITEM 4 - SELECTED CONSOLIDATED FINANCIAL INFORMATION

Selected Historical Financial Information

(millions of dollars except per share data)

Revenue and Net Earnings for the year ended December 31	2002	2001	2000
Total Revenue	5,746	6,239	5,978
Operating income	23	357	1,019
Net income	47	152	490
Basic and diluted earnings per common share:			
Operating income	0.09	1.39	3.98
Net income	0.18	0.59	1.91
Dividends per common share	0.52	1.46	0.80
Financial Position as at December 31	**2002**	**2001**	**2000**
Total assets	17,361	16,686	16,632
Long-term debt (net of current portion)	3,352	3,015	3,219
Shareholder's equity	5,383	5,470	5,693

Share Capital and Sole Shareholder

The authorized share capital of the Corporation consists of an unlimited number of common shares. As at December 31, 2002, 256,300,010 common shares are issued and outstanding, all of which are owned directly by the Province. Holders of common shares are entitled to one vote per share at meetings of the shareholders of the Corporation and to receive dividends if, as and when declared by the Board of Directors of the Corporation. Holders of common shares would participate, *pro rata* to their holding of common shares, in any distribution of the assets of the Corporation upon its liquidation, dissolution or winding up. See *"Business of OPG – Relationship with the Province and Others – Relationship with the Province – Shareholder's Agreement and Dividend Policy"* for a description of the Corporation's dividend policy. No options to purchase securities of the Corporation or of any of its subsidiaries are currently outstanding.

ITEM 5 - MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS

The information which appears under the heading "Management's Discussion and Analysis" in the 2002 financial statements of the Corporation is incorporated herein by reference.

ITEM 6 - MARKET FOR SECURITIES

As at March 31, 2003, none of the Corporation's securities are listed and posted for trading or quoted on any exchange or quotation system.

ITEM 7 - DIRECTORS AND OFFICERS

Directors and Senior Management

The following table sets forth the name, municipality of residence, position with the Corporation and principal occupation of each of the directors and members of senior management of the Corporation as of March 31, 2003.

Name and Municipality of Residence	Position with the Corporation and Period of Service on Board	Principal Occupation
WILLIAM A. FARLINGER[1][2][3][4][5] Toronto, Ontario	Director and Chairman of the Board of Directors since December 1998	Chairman of the Board of Directors
JALYNN H. BENNETT[1][2][3] Toronto, Ontario	Director since December 1998	President, Jalynn H. Bennett & Associates Limited (a consulting firm)
GRAHAM A. BROWN[7] Toronto, Ontario	Director and Chief Operating Officer since October 2000	Chief Operating Officer
O. MARK DE MICHELE[4] Coronado, California	Director since July 1999	Chairman and Chief Executive Officer, Urban Realty Partners L.P. (a real estate limited partnership)
PAUL V. GODFREY[1][4] Toronto, Ontario	Director since December 1998	President and Chief Executive Officer, Toronto Blue Jays Baseball Club (a professional sports team)
L. JACQUES MÉNARD[3][4] Montréal, Québec	Director since April 2002	Chairman, BMO Nesbitt Burns, Toronto and President, Bank of Montréal Group of Companies, Québec
RONALD W. OSBORNE[6] Toronto, Ontario	irector, President and Chief Executive Officer since December 1998	President and Chief Executive Officer
BRIAN A. ROBBINS[2][3][4] Aurora, Ontario	Director since December 1998	President and Chief Executive Officer, Exco Technologies Limited (a manufacturing company)
ARTHUR R. SAWCHUK[1] Toronto, Ontario	Director since December 1998	Chairman of the Board of Directors, Manulife Financial Corp. (an insurance company)
RICHARD M. THOMSON[2] Toronto, Ontario	Director since December 1998	Retired Chairman and Chief Executive Officer, The Toronto Dominion Bank (a Canadian chartered bank)
WAYNE M. BINGHAM Aurora, Ontario	Executive Vice-President and Chief Financial Officer	Executive Vice-President and Chief Financial Officer
RICHARD DICERNI Mississauga, Ontario	Executive Vice-President and Corporate Secretary	Executive Vice-President and Corporate Secretary

Name and Municipality of Residence	Position with the Corporation and Period of Service on Board	Principal Occupation
DAVID W. DRINKWATER ..... Toronto, Ontario	Executive Vice-President – Corporate Development and Legal Affairs	Executive Vice-President –Corporate Development and Legal Affairs
JOHN D. MURPHY ..... Pickering, Ontario	Executive Vice-President – Human Resources and Chief Ethics Officer	Executive Vice-President – Human Resources and Chief Ethics Officer
BRUCE BOLAND ..... Toronto, Ontario	Senior Vice-President – OPG Customer Solutions	Senior Vice-President – Customer Solutions
PIERRE CHARLEBOIS ..... Pickering, Ontario	Chief Nuclear Operating Officer and Chief Nuclear Engineer	Chief Nuclear Operating Officer and Chief Nuclear Engineer
JAMES (JIM) PATRICK TWOMEY..... Toronto, Ontario	Senior Vice-President – Electricity Production	Senior Vice-President – Electricity Production
S. SNICK MEYERS ..... Oakville, Ontario	Senior Vice-President – Trading & Portfolio Management	Senior Vice-President – Trading & Portfolio Management
PATRICK MCNEIL ..... Whitby, Ontario	Senior Vice-President – Nuclear Strategy & Support	Senior Vice-President – Nuclear Strategy & Support
W.R. (BILL) ROBINSON ..... Markham, Ontario	Senior Vice-President – Pickering A	Senior Vice-President – Pickering A
GARY GRANT Pickering, Ontario	Senior Vice-President – Pickering B	Senior Vice-President – Pickering B
GREGORY SMITH..... Toronto, Ontario	Senior Vice-President – Darlington	Senior Vice-President – Darlington
GISELLE S. BRANGET..... Toronto, Ontario	Vice-President and Treasurer	Vice-President and Treasurer
ADÈLE S. MALO..... Toronto, Ontario	Vice-President Law and General Counsel	Vice-President Law and General Counsel
BART W. DEMOSKY Mississauga, Ontario	Chief Risk Officer	Chief Risk Officer

Notes:

(1) Member of the Human Resources and Corporate Governance Committee.

(2) Member of the Audit Committee.

(3) Member of the Environment, Health and Safety Committee.

(4) Member of the Nuclear Review Committee.

(5) Mr. Farlinger has been a director of Laidlaw Inc. since 1994. Laidlaw Inc. filed voluntary petitions to reorganize under Chapter 11 of the U.S *Bankruptcy Code* and under the *Companies Creditors' Arrangement Act* in Canada on June 29, 2001. Attends all committee meetings but is not a member of these committees.

(6) Attends all committee meetings but is not a member of these committees.

(7) May attend Audit, Nuclear Review and Environment, Health and Safety Committee meetings but is not a member of these committees.

All of the directors and senior management of the Corporation have been engaged for more than five years in their current principal occupations except as set out below:

Ronald W. Osborne was President and Chief Executive Officer of Bell Canada (a Canadian telecommunications company) from 1997 to March 1998, President of BCE Inc. (a global telecommunications company) from 1996 to 1997, Executive Vice-President and Chief Financial Officer of BCE Inc. from 1995 to 1996;

Graham A. Brown joined the Corporation in October 2000. Previous to this, he served as Chief Operating Officer of National Power, plc (a U.K.-based electricity generator and retailer) from 1999 to September 2000, prior to which he served as its U.K. managing director from 1998 to 1999, commercial director from 1994 to 1998 and as a director from 1996;

O. Mark De Michele was President and Chief Executive Officer of Arizona Public Service Company (an electrical power utility) from 1988 to 1997;

Paul V. Godfrey was President and Chief Executive Officer of Sun Media Corporation (a communications and media company) from 1996 to June 2000 and President and Chief Executive Officer of the Toronto Sun Publishing Corporation (a newspaper publishing company) from 1992 to 1996;

L. Jacques Ménard was Chairman of Hydro-Québec from 1996 to 2001;

Arthur R. Sawchuk was Chief Executive Officer of Avenor Inc. (a natural resource company) from November 1997 to July 1998 and Chairman, President and Chief Executive Officer of DuPont Canada Inc. (a diversified industrial company) from 1995 to 1997;

Wayne M. Bingham was Senior Vice-President – Finance of Union Gas Limited (a natural gas storage, transportation and distribution company) from 1998 to March 1999 and Vice-President – Finance of Westcoast Energy Inc. (an energy company) prior to 1998;

Richard Dicerni was Senior Vice-President, Corporate and Environmental Affairs and Corporate Secretary of the Corporation from December 1998 to December 1999. Prior to that, he was Senior Vice-President, Corporate and Environmental Affairs, with Ontario Hydro from December 1997 to November 1998. Mr. Dicerni served as President and Chief Executive Officer of the Canadian Newspaper Association (a trade and lobbying organization) from 1996 to December 1997 and held several Deputy Minister positions with the Province from 1992 to 1996, including Deputy Minister of Education and Training and Deputy Minister of Intergovernmental Affairs from 1995 to October 1996;

David W. Drinkwater was Special Advisor to the Chairman and Chief Executive Officer of Bell Canada during 1998, Group Vice-President, Law and General Counsel of Bell Canada from 1996 to 1998 and, prior to that, a partner of Osler, Hoskin & Harcourt (a law firm);

John D. Murphy was President of the Power Workers' Union, CUPE Local 1000 (a labour union), from 1993 to May 2000. He was appointed to OPG's Board of Directors in December 1998. Upon joining OPG as Executive Vice-President – Human Resources in May 2000, he stepped down from the Board of Directors. He was also appointed to the position of Chief Ethics Officer on March 5, 2002;

Bruce Boland was Senior Vice-President, Energy Markets from March 2000 – August 2001, Vice-President, Regulatory Affairs, of the Corporation from April 1999 to March 2000. Prior to that, he was Senior Manager of Regulatory Affairs from May 1997 to March 1999 and Manager of Pricing from October 1995 to May 1997;

Pierre Charlebois was Senior Vice-President, Technical Services and Chief Nuclear Engineer from 1999 to October 2002 when he assumed the responsibilities of Chief Nuclear Operating Officer. He was Vice-President, Station Engineering Support of the Corporation from 1998 to 1999 and was a principal of Performa International (a consulting firm) from 1996 to 1998. Prior to 1996, Mr. Charlebois was Technical Manager, Production Manager and Plant Director at Pickering Nuclear Generating Station;

James (Jim) Patrick Twomey was Chief Executive Officer at Hazelwood Power in Australia from 1996 to 2000. Prior to that Mr. Twomey was General Manager, Operations and Maintenance Development at National Power (UK) from 1994 to 1996;

S. Snick Meyers was President of DTE Energy Trading, a subsidiary of Detroit Edison, from 1996 to August 2001. From 1993 to 1996 Mr. Meyers was Director of Trading, Entergy Power Marketing;

Patrick McNeil was Vice-President, Corporate Development from April 1999 to February 2002. Prior to that, he was Vice-President, Corporate Planning from September 1997 to April 1999 and Vice-President, Strategic and Investment Planning from April 1997 to September 1997;

W.R. (Bill) Robinson was Senior Vice President of Pickering B from February 2002 – October 2002, Site Vice-President, Pickering B Nuclear Generating Station from September 1999 to February 2002. Prior to that he worked at Pickering Nuclear Generating Station as Assistant Site Vice-President from February 1999 to September 1999 and Maintenance Mentor from August 1998 to September 1999. Mr. Robinson was Vice-President, Harris Nuclear Plant, New Hill, North Carolina from 1993 to 1998;

Gary Grant was appointed Senior Vice-President, Pickering B, in October 2002. Prior to this he was Acting Site Vice President, Pickering B from March 2002 to October 2002. Previous to this he was Assistant Vice President, Pickering B from May 2001 to March 2002. He joined the Corporation in March 2000 as Assistant Vice President, Station Improvement, Bruce B Nuclear. From 1997 to March 2000, Gary Grant worked at the Institute of Nuclear Power Operations (INPO) as Manager, in the Heavy Water Reactor Department;

Gregory Smith joined OPG in July 2002. Prior to joining OPG, he worked for 10 years at Energy Northwest where he held several positions including Operations Manager, Plant General Manager and Vice-President, Generating Resources;

Giselle S. Branget was Vice-President and Chief Financial Officer of Integrex, a service-based subsidiary of Owens Corning Corporation (a manufacturing company) from May 1999 to March 2000. Prior to that, Ms. Branget was Vice-President of Strategic Planning and Corporate Development of Owens Corning Corporation, responsible for various finance, strategy and corporate development initiatives, from March 1998 to April 1999 and served as Controller of Fibreboard Corp. (a subsidiary of Owens Corning Corporation) from September 1997 to February 1998. Ms. Branget was Treasurer of John Labatt Limited (a brewing, broadcasting and entertainment company) prior to May 1996;

Adèle S. Malo was Vice-President Legal, General Counsel and Corporate Secretary of Union Gas Limited (a natural gas storage, transportation and distribution company) from May 1998 to August 2000. Prior to that, Ms. Malo was corporate counsel to The Oshawa Group Limited (a wholesale and retail grocery distribution company); and

Bart W. Demosky was Vice President, Risk Services from January 2001 until January 2003 and assumed the responsibilities of Chief Risk Officer in February 2003. Prior to joining the Corporation, he worked at TransAlta Corporation in Calgary as Director, Investor Relations in 2000 and Assistant Treasurer and Director, Corporate Risk Management from 1998 to 2000. From 1996 to 1998 he was Manager, Risk Management Services at Engage Energy (a subsidiary of Westcoast Energy).

Each director is elected annually to serve for a one year term or until his or her successor is elected or appointed except for Mr. William Farlinger who was elected Chair of the Board of Directors for a term to end at the close of the sixth annual meeting of shareholders being approximately May 2005.

Committees of the Board of Directors

Audit Committee. The Audit Committee's mandate includes meeting with the Corporation's external auditors and reviewing the consolidated financial statements of the Corporation prior to the submission of such statements to the Board of Directors. In so doing, the Committee reviews the Corporation's financial and accounting management procedures, including the Corporation's internal accounting and financial controls and procedures, audit procedures and audit plans to ensure compliance with applicable legislative requirements and with generally accepted accounting principles. In addition, the Committee reviews matters relating to the Corporation's risk management programs and policies relating to debt and foreign exchange management. The Committee makes recommendations regarding the mandate and programs of the Corporation's internal auditor and the appointment, terms of engagement and remuneration of the external auditor.

Human Resources and Corporate Governance Committee. The Human Resources and Corporate Governance Committee's mandate includes recommending nominations to the Board of Directors. The Committee also advises the Board of Directors on the Corporation's objectives and policies concerning the recruitment, development, placement and promotion of management as well as remuneration. The Committee is also charged with reviewing the terms of reference of Board committees and ensuring compliance with corporate governance reporting requirements. The Committee is also responsible for reviewing pension plan and executive and management compensation arrangements.

Environment, Health and Safety Committee. The Environment, Health and Safety Committee oversees the Corporation's environment, health and safety policies to ensure compliance with applicable legislative and regulatory requirements. The Committee also evaluates, on an ongoing basis, the adequacy of the Corporation's processes for identifying and managing environmental, health and safety risks and makes recommendations to the Board of Directors to ensure continual improvement in environmental, health and safety performance. The Committee advises the Board of Directors with respect to OPG's operations and maintenance processes to ensure that the radiological risk to workers, the public and the environment is kept within established safety standards. The Committee also monitors and advises the Board of Directors on environmental trends and developments in other jurisdictions that relate to OPG's operations.

Nuclear Review Committee. The mandate of the Nuclear Review Committee is to maintain the oversight of nuclear risks, safety and operations of the Corporation. Specifically, the Committee advises the Board of Directors with respect to the oversight of safe and efficient operations; continuous improvement over the medium and long term; regulatory compliance by OPG's nuclear facilities; and receiving and reviewing reports on OPG nuclear facilities from independent advisors or assessors.

Executive Compensation

The following summary compensation table sets forth the compensation paid by the Corporation for the years ended December 31 2000, 2001 and 2002 to the Chief Executive Officer and the five other most highly compensated executive officers of the Corporation (the "Executive Officers"). This table includes long term incentive plan ("LTIP") payments for the 1999-2001 period which were previously disclosed for the 2001 reported year, such amounts having been paid in 2002. There will be no LTIP payout with respect to the 2000-2002 period. Bonus amounts reported for 2002 are amounts paid in 2003 with respect to fiscal 2002.

Summary Compensation Table[1]

Name and Principal Position	Year	Annual Compensation			All Other Compensation ($)[3]	LTIP Payout ($)
		Salary ($)	Bonus ($)	Other Annual Compensation ($)[2]		
Ronald W. Osborne, Director, President and Chief Executive Officer	2002	850,000	0	92,811[4]	7,956	-
	2001	825,000	752,813	81,841	-	587,500[5]
	2000	775,000	975,000	99,008	-	-
Graham Brown, Director and Chief Operating Officer	2002	750,000	465,500[6]	88, 345[7]	339,840[8]	-
	2001	676,000	465,710[6]	51,697		-
	2000	169,000[9]	84,500	119,436[10]	337,500[8]	-
Wayne Bingham, Executive Vice-President and Chief Financial Officer	2002	346,000	135,459	55,810[11]	1,277	-
	2001	336,000	226,128[12]	49,294	45,000[13]	117,750[5]
	2000	306,000	123,000	51,709	45,000[13]	-
Richard Dicerni, Executive Vice-President and Corporate Secretary	2002	325,000	138,000	53,755[14]	3,042	-
	2001	315,000	131,670	54,666	-	109,375[5]
	2000	300,000	150,000	53,552	-	-
David Drinkwater, Executive Vice-President – Corporate Development and Legal Affairs	2002	412,000	294,000[15]	89,808[16]	1,285	-
	2001	400,000	309,000[15]	52,628	45,000[17]	135,625[5]
	2000	350,000	245,000	50,156	45,000[17]	-
Eugene Preston, Executive Vice-President and Chief Nuclear Officer	2002	1,015,223[18]	76,505[18]	22,500[19]	1,434,124[20]	-
	2001	1,237,488[22]	185,981[22]	33,250	-	246,806[5, 21]
	2000	1,112,148[23]	322,719[23]	32,937	-	-

Notes:

(1) Amounts previously reported for 2000 and 2001 under Other Annual Compensation and All Other Compensation have been reclassified. All bonus amounts paid for special projects are reported under Bonus and moving allowances under Other Annual Compensation.

(2) Includes taxable car allowances, flexible benefits payments, life insurance for 2000 and 2001, financial services, membership fees and moving allowance.

(3) Includes life insurance for 2002.

(4) Includes flexible benefits of $52,811 and car allowances of $40,000.

(5) These Long-Term Incentive Plan payments relate to the 1999-2001 period and were paid in early 2002 and were disclosed in last year's Annual Information Form.

(6) Includes annual incentive bonus and project incentives paid for 2002 and 2001.

(7) Includes flexible benefits of $52,406 and car allowances of $30,000.

(8) Includes deferred signing bonus for 2002 and signing bonus for 2000.

(9) Mr. Brown commenced employment on October 1, 2000. His salary on an annual basis would have been $675,000.

(10) Includes $100,000 moving allowance for 2000.

(11) Includes flexible benefits of $25,810 and car allowances of $30,000.

(12) Includes annual incentive bonus and project incentives for 2001.

(13) Guaranteed transitional award payment per employment contract.

(14) Includes flexible benefits of $23,755 and car allowances of $30,000.

(15) Includes project incentives for 2002 and 2001.

(16) Includes flexible benefits of $31,025, car allowances of $30,000 and membership fees $28,783.

(17) Includes guaranteed transitional award payments per employment contracts.

(18) Mr. Preston retired effective October 2, 2002; 2002 salary of U.S.$643,659 has been converted at an average exchange rate of U.S.$1.00 = C$1.5773 and bonus of $50,000 has been converted at an average exchange rate of U.S.$1.00 =1.5301.

(19) Includes car allowances of C$22,500.

(20) Amounts payable upon retirement include U.S.$850,000 converted at an estimated exchange rate of U.S.$1.00=C$1.4804, C$150,000 to be paid in 2003, including other costs such as legal and accounting fees. The Corporation will also cover specified moving costs related to his relocation to the U.S. Under its Corporate Relocation Program the Corporation has purchased his home for an appraised value.

(21) LTIP payout converted at an exchange rate of U.S.$1.00=C$1.5923.

(22) 2001 salary of U.S.$800,000 has been converted at an average exchange rate of U.S.$1.00 = C$1.5469; 2001 bonus payment of U.S.$116,800 has been converted at the prevailing exchange rates at the time of payment of U.S.$1.00 = $1.5923.

(23) 2000 salary of U.S.$750,000 has been converted at an average exchange rate of U.S.$1.00 = C$1.4829; 2000 bonus payments of U.S.$165,000 and U.S.$50,000 have been converted at the prevailing exchange rates at the time of payment of U.S.$1.00 = C$1.4949 and U.S.$1.00 = C$1.5212, respectively.

Annual Incentive Plan

Effective January 1, 1999, the Board of Directors approved the establishment of an Annual Incentive Plan ("AIP") for management. The plan is designed to incent and reward management for achieving key annual financial and operational objectives that support and help achieve short and long term business strategies.

Each year the Human Resources Corporate Governance Committee establishes Corporate performance goals and measures at threshold, target and stretch levels. Funds available for distribution to the management group

are based on achieving Corporate performance above threshold. Bonus payouts under the plan are based on achieving measured results for Corporate, Business Unit, and individual performance. Individual bonus payments are determined as a percentage of the eligible employee's base salary during the plan year.

Long-Term Incentive Plan

The Board of Directors approved the establishment of a Long-Term Incentive Plan ("LTIP") for senior executives effective January 1, 1999. The objective of the LTIP is to provide an incentive to achieve outstanding performance over a longer term than the one-year period covered by annual bonus awards.

The LTIP operates over three-year overlapping periods. Each performance period starts on January 1 of the first calendar year and ends December 31 of the third calendar year. To be eligible for a payout under the LTIP, a participant must be employed by the Corporation throughout the relevant three-year period and at the end of the three-year period.

The first performance period commenced on January 1, 1999 and ended on December 31, 2001 and resulted in payments in early 2002 disclosed in the table above. These amounts were also disclosed in the Corporation's 2001 filings. The second period commenced January 1, 2000 and ended on December 31, 2002. No payments will be made under the LTIP for that three-year period. Three of these performance periods remain open. The first open LTIP performance period commenced January 1, 2001 and will end on December 31, 2003. The second commenced January 1, 2002 and will end on December 31, 2004, and the most recent commenced January 1, 2003 and will end on December 31, 2005.

LTIP payouts will be determined based on corporate results achieved during each performance period and paid out in cash. The Human Resources Corporate Governance Committee of the Board determines the performance measures and targets applicable to a given performance period at the outset of the performance period. In addition, threshold and maximum performance levels will be established. LTIP payouts will not be paid for performance below threshold. Threshold, target and maximum incentive awards will be expressed as a percentage of the participant's average base salary over the three-year performance period.

The following table illustrates the potential future payouts under the LTIP for the three performance periods which commenced on January 1, 2000, January 1, 2001 and January 1, 2002 for those Named Executive Officers, as of December 31, 2002, who participated in the LTIP. Subject to the terms of individual employment agreements, actual LTIP payouts will not be made until the completion of the relevant three-year performance period and will depend upon performance and the level of the individual's eligible earnings over each of the three-year periods.

Potential Future Payouts in 2003, 2004, and 2005 Under Non-Securities-Price Based Plans [1]

Name	Payment Date	Performance Period Until Maturation or Payout	Threshold ($)	Target ($)	Maximum ($)
Ronald W. Osborne,	Payable in 2005	2002 – 2004	212,500	425,000	637,500
Director, President and Chief	Payable in 2004	2001 – 2003	210,417	420,833	631,250
Executive Officer	Payable in 2003	2000 – 2002	NIL	NIL	NIL
Graham Brown,	Payable in 2005	2002 – 2004	235,000	470,000	705,000
Director and Chief Operating Officer	Payable in 2004	2001 – 2003	222,600	445,200	667,800
	Payable in 2003	2000 – 2002[2]	N/A	N/A	N/A
Wayne Bingham,	Payable in 2005	2002 – 2004	44,000	88,000	132,000
Executive Vice-President and Chief	Payable in 2004	2001 – 2003	43,208	86,417	129,625
Financial Officer	Payable in 2003	2000 – 2002	NIL	NIL	NIL
Richard Dicerni,	Payable in 2005	2002 – 2004	41,458	82,917	124,375
Executive Vice-President and	Payable in 2004	2001 – 2003	40,625	81,250	121,875
Corporate Secretary	Payable in 2003	2000 – 2002	NIL	NIL	NIL
David Drinkwater,	Payable in 2005	2002 – 2004	52,583	105,167	157,750
Executive Vice-President – Corporate	Payable in 2004	2001 – 2003	51,542	103,083	154,625
Development and Legal Affairs	Payable in 2003	2000 – 2002	NIL	NIL	NIL

Notes:

(1) Calculations are based on 2001, 2002 and 2003 salary levels.
(2) Transitional arrangements for Mr. Brown are disclosed in the Employment Agreement section.

Pension Plans

Messrs. Osborne, Brown, Bingham, Dicerni and Drinkwater participate in a registered defined benefit pension plan. The plan provides a benefit at age 65 in conjunction with the Canada Pension Plan of 2% of the highest three year average pensionable earnings per year of credited service, subject to the limits imposed by the *Income Tax Act* (Canada). Pensions are paid on a joint and 66.67% survivor basis to members who have a spouse at the time of retirement. The pension is indexed to the Consumer Price Index after retirement to a maximum increase of 8% per annum. There is also a supplementary pension plan, secured by letters of credit, that provides benefits in excess of the registered plan benefits up to the level of benefits promised to each executive.

The following table shows, as of December 31, 2002, the pensions payable from the Corporation and the Corporation's pension plan at age 65 at various pensionable earnings levels and years of credited service for the above-noted participants.

Pensionable Earnings	Years of Service				
	15	20	25	30	35
$200,000	$57,008	$76,010	$95,013	$114,015	$133,018
$400,000	$117,008	$156,010	$195,013	$234,015	$273,018
$600,000	$177,008	$236,010	$295,013	$354,015	$413,018
$800,000	$237,008	$316,010	$395,013	$474,015	$553,018
$1,000,000	$297,008	$396,010	$495,013	$594,015	$693,018
$1,200,000	$357,008	$476,010	$595,013	$714,015	$833,018
$1,400,000	$417,008	$556,010	$695,013	$834,015	$973,018
$1,600,000	$477,008	$636,010	$795,013	$954,015	$1,113,018

The promised benefits and the credited service for each executive are described below.

Mr. Osborne's credited service at December 31, 2002 is 10.04 years. For each year of service with the Corporation, he will receive 1.25 years of credited service for purposes of calculating his pension plan benefit. Mr. Osborne's pensionable earnings will be comprised of his base salary and the bonus compensation earned in the year and paid in the following year. On retirement, he will also receive a lump sum retiring allowance equal to his annual base salary.

Mr. Brown's credited service at December 31, 2002 is 2.25 years. Mr. Brown's pensionable earnings include his base salary and any bonus earned in the year and paid in the following year. Mr. Brown's pension is based on the average pensionable earnings in his best 36 consecutive months of employment, this average not to exceed the aggregate of his average base salary and average target bonus during the same period. On termination before the age of 55, he will receive a deferred pension, commencing at age 55, equal to 85% of his annual pension based on service and earnings to the date of such termination. If Mr. Brown retires after age 55 and before age 60, his accrued pension based on service and earnings to the date of such termination, shall be payable immediately but will be reduced by 3% per annum for each year that such retirement precedes attaining the age of 60. If he retires on or after attaining the age of 60, his pension will vest immediately and will be payable without reduction. On retirement in accordance with the terms of the pension plans, Mr. Brown will also receive a lump sum retiring allowance equal to his monthly base salary.

Mr. Bingham's credited service at December 31, 2002 is 7.50 years. For each of his first ten years of service with the Corporation, he will receive two years of credited service for purposes of calculating his pension plan benefit. Thereafter he will receive one year credited service for each year of service. Mr. Bingham's pensionable earnings will be comprised of his base salary and the bonus compensation (up to his target bonus) earned in the year and paid in the following year. If Mr. Bingham retires after age 55 and before age 60, his accrued pension based on service and earnings to the date of such termination, shall be payable immediately but will be reduced by 3% per annum for each year that such retirement precedes attaining the age of 60. If he retires on or after attaining the age of 60, his pension will vest immediately and will be payable without reduction. On retirement in accordance with the terms of the pension plans, he will also receive a lump sum retiring allowance equal to his monthly base salary.

Mr. Dicerni's credited service at December 31, 2002 is 33.72 years. This includes credited service transferred from his previous employer. For each of the first 12 years of service commencing January 1, 2000, he will receive 1.5 years of credited service for purposes of calculating his pension plan benefit. Mr. Dicerni's pensionable earnings will be comprised of his base salary and an appropriate portion of his bonus compensation paid in the year. On retirement in accordance with the terms of the pension plans, Mr. Dicerni will receive a lump sum retiring allowance equal to his monthly base salary.

Mr. Drinkwater's credited service at December 31, 2002 is 8 years. For each year of service with the Corporation until age 60, he will receive two years of credited service for purposes of calculating his pension plan benefit. Thereafter he will receive 1.5 years of credited service for each year of service. Mr. Drinkwater's pensionable earnings will be comprised of his base salary and the bonus compensation earned in the year and paid in the following year. On termination before the age of 55, he will receive a deferred pension, commencing at age 55, equal to 85% of his annual pension based on service and earnings to the date of such termination. If Mr. Drinkwater retires after the age of 55 and before age 60, his accrued pension based on service and earnings to the date of such termination, shall be payable immediately but will be reduced by 3% per annum for each year that such retirement precedes attaining the age of 60. If he retires on or after attaining the age of 60, his pension will vest immediately and will be payable without reduction. In addition, the Corporation guarantees that if Mr. Drinkwater is terminated (other than for cause), prior to age 55, he will receive a total pension of not less than $100,000 per annum payable from age 55. If Mr. Drinkwater retires after age 55 and before age 60, his total pension from the Corporation will not be less than $100,000 per annum. If Mr. Drinkwater retires after age 60, his total pension from the Corporation will not be less than $200,000 per annum.

Following payment of the retiring allowance described in note 20 to the Summary Compensation Table, the Corporation has no further obligation to Mr. Preston in respect of pension or other post employment compensation.

Employment Agreements

The Corporation has employment agreements with each of the Named Executive Officers. In addition to their base salary and other LTIP and pension entitlements described above, Messrs. Osborne, Brown, Bingham, Dicerni, and Drinkwater are eligible to receive annual cash awards under the Corporation's Annual Incentive Plan based on the achievement of key corporate, business and individual performance measures.

Mr. Osborne's employment agreement provides that upon involuntary termination without cause Mr. Osborne would receive either one year's notice or, at his or the Corporation's option, a lump sum payment equal to his base salary plus an amount equal to the annual bonus at target, discounted for one year at prevailing interest rates. In addition, all amounts accrued under the Corporation's long term incentive plan will vest immediately and will be paid within 90 days of the date of termination. In addition, if Mr. Osborne elects to terminate his employment as a result of a change of control of the Corporation (other than as a result of a public offering of shares), he will receive the same payments as if he were terminated without cause, except that the notice period shall be two years.

Mr. Brown's first full participation in the LTIP plan will cover the three year performance cycle 2001–2003. Under his employment arrangement he is eligible to earn a transitional amount in respect of 2001 and 2002 to bridge him to full participation. He has been awarded $405,000 under this arrangement which is payable to him in 2003. Mr. Brown is also eligible for certain project incentives related to the Corporation's commercial performance and to his expanded responsibilities in the Nuclear division. The employment agreement with Mr. Brown also provides that in the event that Mr. Brown is terminated without cause by the Corporation, he will be provided a period of notice of one year plus an amount equal to the annual bonus paid for the preceding year, or in lieu of the above, at either Mr. Brown's or the Corporation's option, a lump sum of $1 million. In addition, Mr. Brown will receive all amounts accrued under the long-term incentive plan and project initiatives and, if notice of termination is effective before December 31, 2003, relocation expenses to the United Kingdom and reimbursement for any loss on the sale of his home in Canada. Mr. Brown may elect to terminate his employment if: (i) by the end of 2003 no non-government equity has been invested in the Corporation and there is no reasonable prospect of such equity investment in 2004; or (ii) there is a change in control of the Corporation, other than as a result of a public offering of shares, to which Mr. Brown has not consented (such consent not to be unreasonably withheld or delayed); and, as a result, there is a material change in Mr. Brown's duties or responsibilities. In such event, he will be entitled to receive $1 million plus all amounts accrued under the long-term incentive plan and project initiatives.

The Corporation has entered into an employment agreement with Mr. Bingham which provided for guaranteed awards payable in 2000 and 2001. The agreement provides that in the event that Mr. Bingham is terminated without cause by the Corporation, he will receive a lump sum equal to 18 months' salary.

Mr. Dicerni's employment agreement provides that upon involuntary termination without cause, Mr. Dicerni would receive a period of notice of two years, either as continued payment of base salary or, at Mr. Dicerni's option and with the Corporation's consent, a lump sum payment discounted at a rate based on the average prime rate. Mr. Dicerni would be entitled to any annual or long-term incentive plan amounts that have been accrued at the commencement of the notice period and long-term disability coverage for the duration of the notice period.

The Corporation has entered into an employment agreement with Mr. Drinkwater which guaranteed awards payable in 2000 and 2001 to bridge to the long-term incentive plan. The agreement also provides for a retiring allowance in the event that Mr. Drinkwater is terminated by the Corporation without cause. The amount of the retiring allowance varies based upon Mr. Drinkwater's age and the level of his pension entitlement at the date of termination. If Mr. Drinkwater is terminated without cause before the age of 55, he will receive an amount by which the aggregate of eighteen months salary plus the target level of his annual bonus exceeds the commuted value of the retiring allowance. In addition, upon termination without cause, all amounts awarded under the LTIP shall immediately vest and be paid within 90 days of the date of termination. Mr. Drinkwater may elect to terminate his employment by giving 180 days' notice if: (i) there is a fundamental change in the policies of the Province relating to the Corporation, or (ii) there is a change of control of the Corporation, other than as a result of a public offering of shares, to which Mr. Drinkwater has not consented (such consent not to be unreasonably withheld or delayed); and, as a result, there is a material change in Mr. Drinkwater's duties and/or responsibilities. In such event he will receive the same payment as if he were terminated without cause.

Compensation of Directors

The Corporation's Chairman, William A. Farlinger, is remunerated at a level of $250,000 per annum with such perquisites and benefits provided to senior executives of the Corporation, including pension. Mr. Farlinger's credited service at December 31, 2002, is 7.16 years. At retirement, Mr. Farlinger's pension shall consist of $6,000 per annum for each full year of service, plus a pro rated amount for any part years, subject to consumer price index adjustments and with provisions for spousal survivor benefits.

The by-laws of the Corporation provide that directors may receive reasonable remuneration for their services, commensurate with their duties, together with reimbursement for all reasonable expenses incurred in fulfilment of their duties, including travelling expenses. The amount of such remuneration is determined by the Board of Directors from time to time. Directors currently receive a $25,000 annual retainer plus $900 for each Board and committee meeting attended. In addition to other fees, the chair of each committee is paid a $3,000 annual retainer. These fees are paid non-adjusted, in U.S. currency to the one U.S. resident Director of the Board.

ITEM 8 - ADDITIONAL INFORMATION

Additional information, including details of directors' and officers' remuneration and indebtedness, principal holders of the Corporation's securities, options to purchase securities and interests of insiders in material transactions, where applicable, is also contained in the Corporation's annual filing of a reporting issuer, filed with the Canadian securities commissions instead of a management information circular. Additional financial information is provided in the Corporation's annual comparative financial statements for the year ended December 31, 2002. A copy of:

- this annual information form, together with any material incorporated by reference;
- the Corporation's annual filing of a reporting issuer;

- the Corporation's annual comparative financial statements for its most recently completed financial year, together with the accompanying report of the Corporation's auditor, as filed with the Canadian securities commissions; and

- the Corporation's most recent interim financial statements for a period after the end of the Corporation's most recently completed financial year, as filed with the Canadian securities commissions;

may be obtained on written request to the Secretary, Ontario Power Generation Inc., 700 University Avenue, Toronto, Ontario, M5G 1X6 (Attention: Investor Relations). These documents, together with any other requested documents that are incorporated by reference in a preliminary short form prospectus or short form prospectus, will be provided free of charge while the Corporation's securities are in the course of a distribution under the preliminary short form prospectus or short form prospectus. At any other time, these documents will be provided, although payment of a reasonable charge may be required if the request is made by a person who is not a security holder of OPG. These documents are also available on OPG's website, at www.opg.com.

GLOSSARY

Organization Abbreviations

AECB	-	Atomic Energy Control Board (now the CNSC)
AECL	-	Atomic Energy of Canada Limited, a Federal Crown corporation and Canada's nuclear research and development organization, which is responsible for the design, marketing and construction of CANDU power reactors
CNSC	-	Canadian Nuclear Safety Commission (formerly the AECB)
FERC	-	Federal Energy Regulatory Commission, the independent regulatory agency with the U.S. Department of Energy that regulates the transmission and wholesale sale of electricity in interstate commerce
Hydro One	-	Hydro One Inc. and its subsidiaries
IMO	-	Independent Electricity Market Operato r
Minister	-	Ontario Minister of Energy
OLB	-	Ontario Energy Bo ard
OEFC	-	Ontario Electricity Financial Corporation

Technical and Operational Terms

"Acquired Business" refers to Ontario Hydro's electricity generation business, the assets, liabilities, employees and obligations of which were purchased and assumed by OPG on April 1, 1999 pursuant to the *Electricity Act, 1998* (Ontario);

"aggregator", **"broker"** and **"marketer"** each refer to a profit-motivated entity that acts as an intermediary in arranging transactions between or on behalf of generators and customers. It may assemble load or generation into larger blocks (an aggregator), act as a negotiator between buyers and sellers (a broker), or buy, sell and take physical positions in the marketplace (a marketer);

"ancillary service" means a service necessary to maintain the reliability of the IMO-controlled grid;

"automatic generation control" means the process that automatically adjusts the output from a generation facility based on automated, electronic signals in order to provide frequency control and to maintain the balance between load and the output from generation facilities;

"availability", when used in reference to a generating unit, is a measure of mechanical reliability represented by the percentage of time a generating unit is capable of providing service, whether or not it is actually in-service, relative to the total time for the period;

"base load capacity" is generating capacity used to serve an essentially constant level of customer demand; typically, base load units operate whenever they are available and have capacity factors greater than 60%;

"bilateral contract" is a contract for the purchase and sale of notional electricity usually entered into directly between a generator and an end-user or between a generator or end-user and a market intermediary;

"black start capability" means the demonstrated potential for a generation facility (as established by tests in accordance with the provisions of an ancillary service contract) to start without electrical system supply; it is the intention of the IMO to use the energy of such a generation facility to energize a defined portion of the IMO-controlled grid;

"CANDU" is an acronym for Canadian Deuterium Uranium, a family of nuclear fission reactors developed in Canada which use pressurized heavy water coolant or deuterium as a moderating agent and natural uranium (uranium dioxide) as fuel;

"capability factor" is the amount of energy capable of being produced by a generating unit as a percentage of its maximum output assuming no external constraints such as transmission limitations;

"capacity factor" is an operational statistic which is determined for a period of time, usually one year. The capacity factor of a generating asset is usually specified as a percentage and is defined as the ratio of the amount of energy that the asset actually generated over a period of time; divided by the amount of energy that the asset would have produced over the same period of time if it had operated continuously at full capacity. Capacity factors depend on whether a facility is used for continuous, intermittent or occasional operation, related operational decisions, such as planned outages and weather. The average capacity factor for a portfolio of generating units may vary from these values due to the number of units in the portfolio and the operating characteristics of those units;

"capacity reserve" means generation capacity that would be bid into a real-time market to address concerns about low reserve margins, the security of the electricity system and the adequacy of the electricity system to meet the demand for energy;

"certified black start facility" means a registered facility that, to the satisfaction of the IMO acting reasonably, has complied with and continues to comply with equipment and staffing configurations, training and maintenance programs and inspection and testing regime as set out in the Market Rules or the Ontario power system restoration plan, and from which the IMO may direct the delivery of power without assistance from the electrical system;

"decommissioning" refers to those actions taken in the interest of health, safety, security and protection of the environment to retire a nuclear facility permanently from service and render it to a predetermined end-state (final or interim) condition;

"decontrol" means the mandated transfer of effective control in respect of output, being control over the timing, quantity and bidding into the Ontario market of such output;

"demand-side bidding" means an agreement between the IMO and an electricity user to reduce the user's consumption (load) of electricity by agreed amounts under specified circumstances;

"**forced outage**" means the removal from service availability of a generating unit, transmission line, or other facility for emergency reasons or unanticipated failure;

"Gg" means a gigagram, or one billion grams;

"head" means the difference between water levels at the intake and outflow of a hydroelectric generating station;

"IMO-administered markets" means the markets established by the Market Rules;

"IMO-controlled grid" means the transmission systems in Ontario which are under the direction of the IMO;

"interconnection" means a transmission line which carries power across the service area boundary of geographically adjacent jurisdictions;

"installed capacity" is the highest level of output which a generating unit is designed to maintain indefinitely without damage to the unit;

"in-service capacity" is that portion of installed capacity that has not been removed from service;

"**intermediate capacity**" is generating capacity intended to operate fewer hours per year than base load capacity but more than peaking capacity; typically, intermediate capacity units have capacity factors ranging from 30% to 60%;

"kilo" is a prefix meaning one thousand; a kilowatt (kW) is 1,000 watts;

"kWh" means a kilowatt hour and is the commercial unit of electric energy. A kWh is the amount of electricity consumed by ten 100W light bulbs burning for one hour;

"load" means the quantity of electricity consumption measured as either the energy consumed over a given period of time or the rate of energy consumption at a given time by a particular customer or group of customers;

"market power mitigation" is a framework composed of a combination of a price cap and rebate mechanism and decontrol of capacity obligations that was approved by the Province in order to protect the interests of consumers while ensuring an orderly and gradual transition to a long-run industry structure in which OPG's generating capacity available to the Ontario market is substantially reduced;

"Market Rules" are rules made and enforced by the IMO that govern the IMO-controlled grid and that establish and govern the IMO-administered markets relating to electricity and ancillary services;

"mega" is a prefix meaning one million; a megawatt (MW) is 1,000,000 watts or 1,000 kW;

"municipal electrical utility" or **"MEU"** refers to an entity that purchases power at wholesale and distributes it at retail prices to connected customers within a defined geographical area, typically a city or town;

"must-run contracts" are contracts between the IMO and a generator which allow the IMO to call on a generator's facility, at times when the facility may not otherwise be available for production, in order to maintain the reliability of the electrical system;

"MWh" means a megawatt-hour and is equal to 1,000 kWh;

"Market Opening" is the introduction of competition in Ontario to supply electricity in both the wholesale and retail markets through the opening of access to Ontario's transmission and distribution systems which occurred on May 1, 2002;

"operating reserve" means the capacity that can be called upon on short notice by the IMO to replace scheduled energy supply that is unavailable as a result of an unexpected outage or to augment scheduled energy as a result of unexpected demand or other contingencies;

"peaking capacity" means generating capacity intended to be operated intermittently to provide power during maximum load peaks; typically, peaking capacity units have capacity factors of less than 20%;

"**planned outage**" means the removal of equipment from service availability for inspection and/or general overhaul of one or more major equipment groups. This outage usually is scheduled well in advance;

"reactive support/voltage control service" means the control and maintenance of prescribed voltages on the IMO-controlled grid;

"Standard Supply Service" means the sale of electricity in accordance with the provisions of section 29 of the *Electricity Act, 1998* and the OEB Standard Supply Service Code;

"stranded debt" is defined under the *Electricity Act, 1998* as the amount of debt and other liabilities of OEFC that, in the opinion of the Minister of Finance, cannot reasonably be serviced and retired in a competitive electricity market;

"tera" is a prefix meaning one trillion; a terawatt (TW) is 1,000,000,000,000 watts or 1,000,000,000 kW or 1,000,000 MW;

"Tg" means a teragram, or one trillion grams;

"tonne" means 1,000 kilograms or 2,204.6 pounds;

"TWh" means a terawatt hour and is equal to 1,000,000 MWh;

"unit" means an electrical generator, together with its driving turbine and auxiliary equipment;

"W" or "**watt**" is a scientific unit of electric power representing the rate of work of one joule per second; and

"weather-normalized" means an adjustment to demand statistics in a market to account for the deviation of weather from normal weather conditions in that market.